EXHIBIT
O

Attachment 1: Trial Declaration of Dr. Joan Meyer

[The names and parties submitting this document are listed on the page immediately following this caption page]

UNITED STATES DISTRICT COURT
CENTRAL DISTRICT OF CALIFORNIA
WESTERN DIVISION

UNITED STATES OF AMERICA and PEOPLE OF THE STATE OF CALIFORNIA, *ex rel.* CALIFORNIA DEPARTMENT OF FISH AND WILDLIFE and CALIFORNIA REGIONAL WATER QUALITY CONTROL BOARD, CENTRAL COAST REGION,

Plaintiffs,

v.

HVI CAT CANYON, INC., f/k/a GREKA OIL & GAS, INC.,

Defendant.

CV 11-05097 FMO (SSx)

TRIAL DECLARATION OF DR. JOAN K. MEYER

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I, Joan K. Meyer, declare as follows:

1. The Plaintiffs in this litigation requested that I provide my expert opinions in this case regarding two distinct economic issues: 1) the economic benefit, if any, gained by Defendant HVI Cat Canyon, Inc. ("HVI-CC") through non-compliance with the Clean Water Act, the Oil Pollution Act of 1990, and their implementing regulations; and 2) the financial condition of HVI-CC, as well as HVI-CC's financial transactions with affiliated entities.

2. At the request of counsel, I submitted an expert report addressing my conclusions on economic benefit on February 9, 2017. On March 10, 2017 and again on May 2, 2017, I supplemented this report to reflect corrections made by expert witness Michael Kinworthy to data I relied upon in reaching my opinions. A true and correct copy of my report on economic benefit, modified to incorporate these corrections, is attached as Exhibit A ("Economic Benefit Report"). On February 9, 2017, I also submitted an expert report addressing my conclusions on HVI-CC's financial condition, a true and correct copy of which is attached as Exhibit B ("Financial Condition Report"). After the final deposition transcript for HVI-CC's Rule 30(b)(6) witness James Johnson became available, I supplemented my opinion on March 10, 2017, and a true and correct copy of my supplemental report is attached as Exhibit C ("Supplemental Financial Condition Report").

3. Rather than restate the entirety of the attached expert reports in this declaration, I adopt and incorporate them here by reference as my testimony under oath. Below, I summarize the opinions expressed in my expert reports. Based on new information produced by HVI-CC after my Financial Condition Report was submitted, I have updated Exhibits 1-4 to that report. These updated Exhibits are attached here as Exhibit D ("Updated Financial Condition Exhibits").

Expert Qualifications

4. I am a Principal of Industrial Economics, Incorporated, an economics and policy consulting firm located at 2067 Massachusetts Avenue, Cambridge, Massachusetts 02140. I have a Ph.D. (1985) and Masters (1982) degrees from Cornell University, Ithaca, New York, in which my major field was environmental and natural resource economics and my minor fields were corporate finance and quantitative methods. I also have a B.S. degree from the University of California, Berkeley. This declaration is based on my personal knowledge and expertise.

5. I have served as a consultant since 1985, focusing on providing economic and financial analysis services. I estimate that over the past 20 years, I have estimated the economic benefit gained by non-compliance with environmental requirements in scores of cases and evaluated the ability to pay of more than 300 businesses.

Methodology

6. The opinions I provide in this declaration and in my expert reports are based on my education and expertise in economic and financial analysis, experience with conducting financial analyses, independent research of certain publicly available information, and my review of documents produced in this litigation. My opinions reflect widely accepted financial and economic analysis principles.

Statement of Opinions: HVI-CC's Economic Benefit from Noncompliance

7. In my Economic Benefit Report, I state my primary opinion that HVI-CC gained an estimated economic benefit of **$6,317,199** in net present value

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terms as of June 20, 2017. (June 20, 2017, was the trial date at the time I completed my Economic Benefit Report.)

8. The United States alleges numerous violations (including oil spills) of the Clean Water Act, the Oil Pollution Act of 1990, and their implementing regulations at multiple facilities owned and operated by HVI-CC. By delaying (in some cases) or avoiding (in other cases) the costs of compliance, HVI-CC gained an economic benefit compared to if it had complied on time. These costs of compliance consist of expenditures to prevent oil spills and/or to meet obligations under environmental regulations.

9. When compliance costs are delayed, the company has use of the money that should have been spent on compliance to invest in other activities. In this way, the company realizes an economic benefit from the "return" (as measured by HVI-CC's estimated time value of money) it expects to earn on the money that should have been spent sooner on compliance, by putting that money to use in endeavors it expects to be more profitable. It continues to accrue the "return" until it spends the money on compliance.

10. When compliance costs are avoided, the company never incurs the required costs. In the most basic sense and in contrast to costs that are delayed, it realizes an economic benefit from both the "principal" (i.e., the cost of the avoided compliance activity) *and* the "return" (i.e., time value of money) from not spending the money on the compliance activity. For example, several of the violations asserted by the United States concern HVI-CC's failure to follow proper protocols for testing, monitoring, and/or recordkeeping; even if HVI-CC begins complying with these requirements in the future, the company will not incur any expenses related to its past non-compliance . As another example, HVI-CC sold the U-Cal lease in 2009 and therefore cannot undertake any corrective action (nor incur

related expenses) at this lease in the future. Under both examples, HVI-CC gains a benefit equal to the costs it should have spent, plus the return (as measured by HVI-CC's estimated time value of money) it has earned on the avoided costs since then.

11. I estimated the economic benefit realized by HVI-CC using a discounted cash flow ("DCF") model that compares the cash flows the company would have spent had it fully complied on time (i.e., a "full compliance" scenario) with cash flows the company is estimated to have actually spent (i.e., an "actual" scenario). DCF analysis is a widely accepted financial methodology that accounts for the fact that a dollar today is worth more than a dollar next year because that dollar can be invested to earn a return (i.e. "time value of money"). As such, DCF analysis converts cash flows that occur at different points in time to a common time period by accounting for the time value of money. DCF analysis is a widely accepted financial methodology used to evaluate investments and businesses and is used to evaluate economic benefit for failure to comply on time with environmental requirements.

12. To estimate cash flows under both scenarios, I rely on information from Michael Kinworthy, another expert witness testifying in this case for the United States. This information is summarized in Appendix D of Mr. Kinworthy's report (TREX US3214) and described in my Economic Benefit Report.

13. The information from Mr. Kinworthy's report provides several key inputs for my calculations, specifically: estimated costs that HVI-CC reasonably would have been expected to spend to come into compliance on-time with each of the environmental requirements that the United States asserts HVI-CC violated; estimated dates on which HVI-CC was required to make these expenditures in order to be in full compliance; estimated compliance costs incurred by HVI-CC;

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and estimated and actual dates on which HVI-CC incurred compliance-related expenditures. I understand that these compliance costs include expenditures for industry-standard practices that HVI-CC should have undertaken to prevent oil spills and to meet regulatory obligations, whether or not the practice is specified in the law.

14. As an illustration of how I used Mr. Kinworthy's inputs regarding avoided costs, U-Cal item #1 in Appendix D of Mr. Kinworthy's report provides information related to HVI-CC's failure to develop a Spill Prevention, Control, and Countermeasure (SPCC) Plan that met regulatory requirements, from August 2002 until it sold the lease on January 1, 2009, at an estimated one-time avoided cost of $5,000. With this information, I estimate the economic benefit derived from the cost avoided by HVI-CC, as shown in the calculations for U-Cal item #1 in Appendix B of my Economic Benefit Report. As a result of the avoided cost, the company benefited from not only the cost itself, but also the return it earned on the avoided cost.

15. As an illustration of how I used Mr. Kinworthy's inputs regarding delayed costs, Bell item #2 in Appendix D of Mr. Kinworthy's report provides information related to HVI-CC's failure to identify and mark 134 flow lines, from November 1999 through August 1, 2010, at an estimated one-time delayed cost of $33,500. With this information, I estimate the economic benefit derived from the cost delayed by HVI-CC, as shown in the calculations for Bell item #2 in Appendix B of my Economic Benefit Report. As a result of the delayed cost, the company benefited from the return it earned on the cost between 1999, when it should have spent the money, and 2010, when the money was actually spent.

16. As explained in my Economic Benefit Report, my calculations account for depreciation and tax effects, and adjust all dollar amounts over the time period

of 1999 through 2017 to account for the time value of money. To account for differences in value between cash flows that occurred at different points in time, I translate all nominal cash flows into net present value terms as of a single date, June 20, 2017 (i.e., the original date of the trial). To make this adjustment, I employ the estimated weighted average cost of capital (WACC) for HVI-CC to estimate the company's time value of money. The WACC is the most widely-used approach for estimating a company's time value of money, also commonly referred to as the discount rate, to be used in DCF analysis.

17. The WACC estimates the return that investors demand from the company in return for their investment. It represents a firm's cost of doing business – the minimum return that must be generated in order to remain operational over the long term without investors choosing to invest their money elsewhere in investment options that present a better risk-return profile. I did not have sufficient information to estimate a company-specific WACC for HVI-CC; thus, as a proxy, I instead used an industry-wide average for the crude petroleum and natural gas industry. The average WACC (as measured on an after-tax basis) from 1999 – 2016 was 10.13 percent.

18. The difference between the net cash flows under the "full compliance" scenario and the net cash flows under the "actual" scenario (after translating each figure into net present values as of June 20, 2017) is the overall economic benefit of non-compliance accruing to HVI-CC as a result of its non-compliance. I calculated this figure to be **$6,317,199**. The detailed underlying calculations can be found in Appendix B of my Economic Benefit Report.

19. My estimate incorporates conservative assumptions. Under a range of plausible assumptions, one could calculate a higher reported economic benefit than the one I calculated here. In addition to the conservative assumptions described in

my Economic Benefit Report, my estimate does not account for any economic benefit accrued after June 20, 2017. My estimate, therefore, is a conservative estimate.

20. Since submitting my Economic Benefit Report, I have been informed by counsel for the United States that one cost item—Bell Lease item #1 in Mr. Kinworthy's Appendix D (TREX US3214)—contains an error in the date of the actual compliance expenditure. The date is listed as 4/7/2011 but should be 4/27/2011. This error is in HVI-CC's favor (i.e., results in a lower economic benefit estimate) because my calculations assume that economic benefit related to the item stopped accruing on 4/7/2011 rather than 4/27/2011. This error does not materially change my opinion and reinforces that my estimate is a conservative estimate.

Statement of Opinions: HVI-CC's Finances and Transactions with Affiliated Entities

21. I completed my Financial Condition Report in February 2017, incorporating accounting documents produced by HVI-CC that reflected its performance through the third quarter of 2016, and my analysis accurately reflected its financial condition at that time. HVI-CC provided additional financial information relevant to my opinions on July 17, August 17, September 10, and September 13 of 2018.[1] Based on my review, this new information appears consistent with the opinions expressed in my February 2017 report. Although I do not believe it is necessary to update my report, I discuss the relevance of certain

[1] Late the night before this Declaration was due to be filed with the Court (September 13, 2018), HVI-CC provided additional financial information. I have not had an opportunity to review these documents and reserve the right to supplement this Declaration, as appropriate.

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new information revealed in the recent productions by HVI-CC in this Declaration. I also understand that HVI-CC is under a continuing obligation to supplement its responses to the United States' requests and interrogatories. As a result, I may supplement this Declaration before trial, as appropriate.

22. In my February 2017 Financial Condition Report, I state three primary opinions on HVI-CC's finances as of the third quarter of 2016, and as to its history of transactions with affiliated entities, which I have updated where possible to reflect newer information provided by HVI-CC:

a. HVI-CC has not been managed as if it were a standalone business. Instead, it has consistently been managed in concert with its affiliated entities. I have not seen anything to suggest this practice will change.

b. As of the third quarter of 2016, HVI-CC's financial condition had been weak for a number of years. In 2016 the company negotiated a major debt restructuring that effectively eliminated approximately $100 million in liabilities from its balance sheet. Even so, in 2016 HVI-CC was relying on funds from an affiliate to remain in operation. Based on the supplemental information provided by the defendant, HVI-CC's financial condition has remained weak from the third quarter of 2016 through May 31, 2018.

c. GLR, LLC, an affiliate that is also controlled by Mr. Randeep S. Grewal, has been able and willing to lend funds to GIT which are then loaned on to HVI-CC, including $6.7 million loaned to HVI-CC in 2016 that allowed HVI-CC to continue in operation despite its

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financial difficulties.[2] I have not seen anything to suggest this practice of support from affiliates will change.

Below, I summarize the basis for each of these opinions.

HVI-CC has been Managed in Concert with its Affiliates

23. Mr. Randeep S. Grewal ultimately owns and controls HVI-CC, as well as numerous directly and indirectly affiliated entities, as shown on the "HVI Cat Canyon, Inc. Organization Chart" that I prepared as part of my testimony.[3] HVI-CC's direct parent is the holding company GOGH, LLC, which is in turn owned by GIT, Inc. ("GIT"). GIT also owns at least four other companies,

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[2] In my February 19, 2017 expert report, I appropriately relied on the information then available which suggested that in 2016, HVI-CC had received $7.5 million in loans ultimately sourced from GLR, LLC. Recently submitted information from HVI-CC's 2016 audited financial statement (TREX US3233 at HVI085666) shows that the 2016 cash proceeds from the loan at issue were in fact $6.7 million.

[3] An updated version of the HVI-CC Organization Chart is attached to this declaration as Exhibit D.1. The original chart was included as Exhibit 1 to my Expert Report (which is itself attached to this declaration as Exhibit B). I have made the following updates and corrections: I added a dotted line between Randeep S. Grewal and GLR, LLC to better indicate the control that Randeep S. Grewal exercises over GLR, LLC. Deposition of Susan Whalen, Esq., October 4-5, 2016 ("Whalen Dep."), 286:21-22). TREX US2744 at HVIFIN0001356 (6/1/08 Credit Agreement between GIT and GLR) in which Grewal signed as the Chief Executive Officer (CEO) of GRL. I also updated the chart to reflect new information that was provided to me revealing that Rincon Island Limited Partnership is now fully owned by RILP-H, LLC. Furthermore, Greka Construction, LLC changed its name to GCL1, LLC and GRC, Inc. changed its name to California Asphalt Production, Inc. I amended the chart accordingly to reflect those changes and added the respective sources. Moreover, I corrected information on the incorporation state and date of formation of GIN, LLC, GIT, Inc., GCL1, LLC, and Rincon Island Limited Partnership, and included the full name (Grewal Land Holdings, LLC), rather than the abbreviation (GLH, LLC), of one of the former names of GLR.

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including GRC, Inc., which operates an asphalt refinery in Santa Maria and is the primary customer for the crude oil HVI-CC produces.[4] HVI-CC is also affiliated with GLR, LLC ("GLR")[5] which, like HVI-CC, is controlled by Mr. Grewal.[6] By

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[4] Deposition of Randeep Singh Grewal, October 11-12, 2016 ("Grewal 10/11-12/16 Dep.") at 276:22-277:5; Deposition of Jim Johnson, January 26, 2017 ("Johnson 30(b)(6) Dep.") at 36:7-9; TREX US2619 at HVI065317 and 323, TREX US2620 at HVI076583 and 589, TREX US2590 at HVI084242 and 249, and TREX US3233 at HVI085664 and 671 (HVI-CC Consolidated Financial Statements Years Ended December 31, 2011-2016). GRC, Inc. was incorporated as Santa Maria Refining Company, Inc. on August 20, 1993. Articles of Incorporation of Santa Maria Refining Company, filed with the California Secretary of State August 20, 1993. On September 11, 2013, Santa Maria Refining Company, Inc. changed its name to Greka Refining Company, Inc. Certificate of Amendment of Articles of Incorporation of Santa Maria Refining Company, Inc., filed with the California Secretary of State September 11, 2013. Greka Refining Company subsequently changed its name to GRC, Inc. on August 22, 2016. Certificate of Amendment of Articles of Incorporation of Greka Refining Company, Inc., filed with the California Secretary of State August 23, 2016. Finally, GRC, Inc. recently changed its name to California Asphalt Production, Inc. on July 31, 2018. Certificate of Amendment of Articles of Incorporation of GRC, Inc., filed with the California Secretary of State July 31, 2018. For convenience, I refer to the entity as GRC, Inc. in this declaration.

[5] Whalen Dep. at 26:21-27:22, 42:14-25, 92:20-93:2; Grewal 10/11-12/16 Dep. at 266:2-267:3, 274:9-23; Rule 30(b)(6) Deposition of Randeep Singh Grewal, January 6, 2017 ("Grewal 30(b)(6) Dep.") at 17:10-19:1; TREX US2744 at HVIFIN0001356 (Credit Agreement dated as of June 1, 2008, Greka Integrated, Inc. and Greka Land Holdings, LLC). GLR was incorporated as Grewal Finance, LLC on February 25, 2005. It changed its name to Greka, LLC on December 7, 2006. It changed its name once again to Greka Land Holdings, LLC on April 19, 2007, and then again to Grewal Land Holdings on October 11, 2012. Finally, it changed its name to GRL, LLC on January 8, 2015. Delaware Secretary of State, Entity Details for GRL, LLC. For convenience, I refer to the entity as GRL in this declaration.

[6] Whalen Dep. at 286:17-22. In its 2009-2010 financial statements, GIT identified the lender on its note payable-related party as its sole stockholder. TREX US2623

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affiliates, I employ the definition used by the U.S. Securities and Exchange Commission of entities that are under common control either directly or indirectly through one or more intermediaries.[7] In this case, all of the HVI-CC affiliates I discuss are under the common control of Mr. Grewal.

24. Since 2005, HVI-CC has entered into numerous transactions with affiliates, many of which have been to the detriment of HVI-CC. For example, in 2005, HVI-CC took on $79 million of its then-parent corporation GIT's debt, in exchange for a $79 million promissory note from GIT which carried an annual interest rate of 6 percent.[8] The promissory note stated that GIT was to make annual cash payments to HVI-CC equal to the federal income tax payments HVI-CC would have made had it filed federal income taxes as a standalone company, with any remaining balance (including interest) due upon the note's maturity.[9] Thus, the promissory note stipulated that in years when HVI-CC reported taxable net income, GIT would make a cash payment to HVI-CC equivalent to the tax liability

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at HVI065398 (Consolidated Financial Statements of GIT, 2009-2010, Notes to Financial Statements). The only related party loan that existed at that time was a loan from GLR to GIT dated June 1, 2008. TREX US2744 at HVIFIN0001356 (Credit Agreement dated as of June 1, 2008, Greka Integrated, Inc. [GIT] and Greka Land Holdings, LLC [GLR]). This indicates that as of the 2009-2010 GIT financial statements, GLR was the sole stockholder of GIT.

[7] Cornell Law School Legal Information Institute. 17 CFR 230.405 – Definition of Terms. Accessed at https://www.law.cornell.edu/cfr/text/17/230.405

[8] TREX US2587 at HVI066336 (Promissory Note from Greka Integrated, Inc. [GIT] to Greka Oil & Gas, Inc. [HVI-CC] dated August 26, 2005).

[9] TREX US2587 at HVI066336-340 (Promissory Note dated August 25, 2005, and First Amendment to Promissory Note dated July 20, 2010, attached to Tax Sharing Agreement between Greka Integrated, Inc. [GIT] and Greka Oil & Gas, Inc. [HVI-CC], dated January 15, 2013).

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HVI-CC would have owed if it were a standalone company. That payment would reduce the principal GIT owed on the promissory note. However, even if HVI-CC never reported taxable net income in the years from the date of the promissory note to the maturity date, GIT was still required to repay HVI-CC the full principal of $79 million, plus the interest accrued on that principal, by no later than the maturity date. HVI-CC's audited financial statements consistently stated from 2005 through 2012 that "Management considers the [promissory note] to be collectible from the parent."[10] However, it appears that no cash payments were ever made on the promissory note.[11] Additionally, no interest ever accrued on the outstanding principal.[12] In 2010, HVI-CC and GIT extended the maturity date of the promissory note to 2030, without compensation to HVI-CC.[13] Then, in 2013, HVI-CC and GIT canceled the promissory note and replaced it with a tax sharing

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[10] TREX US2610 at HVIFIN0002077, TREX US2662 at HVI084326, TREX US2588 at HVI065341, and TREX US2619 at HVI065323 (HVI-CC and Subsidiary Consolidated Financial Statements Years Ended December 31, 2005-2012).

[11] Note that in 2010 GIT extinguished $35.9 million of its debt to HVI-CC by reducing HVI-CC's debt burden on a note to a third party. GIT did not make a cash repayment of its debt, and this extinguishment did not reduce the principal of $79 million owed on the promissory note. Johnson 30(b)(6) Dep. at 94:12-95:12; TREX US2588 at HVI065336 (Greka Oil & Gas and Subsidiary [HVI-CC] Consolidated Financial Statements Years Ended December 31, 2010 and 2009); TREX US2587 at HVI066334 (Tax Sharing Agreement between Greka Integrated, Inc. [GIT] and HVI Cat Canyon, Inc., January 15, 2013).

[12] Johnson 30(b)(6) Dep. at 47:22-48:12, 48:18-49:3.

[13] TREX US2587 at HVI066340 (First Amendment to Promissory Note dated July 20, 2010, attached to Tax Sharing Agreement between Greka Integrated, Inc. [GIT] and Greka Oil & Gas, Inc. [HVI-CC], dated January 15, 2013); Johnson 30(b)(6) Dep. at 49:4-50:7.

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agreement that is fundamentally different than the promissory note it replaced. Instead of requiring cash payments to HVI-CC from GIT, the tax sharing agreement credits GIT for the federal income taxes it pays on behalf of HVI-CC. In addition, the tax sharing agreement does not allow for interest to accrue to the amount owed to HVI-CC, has no maturity date on which GIT would pay HVI-CC the balance of the principal, includes no protections for HVI-CC if GIT files for bankruptcy, and terminates immediately if HVI-CC is sold outside of the GIT group.[14] Again, HVI-CC received no compensation for agreeing to these changes.[15]

25. HVI-CC pays high interest rates when it borrows from its affiliates, but has not charged interest when it lends to its affiliates. HVI-CC lent approximately $13 million to GIT in 2006.[16] It then lent $15 million to GLR in 2007.[17] These loans were apparently provided interest-free, as HVI-CC has not ever recorded interest income on its income statements through May 31, 2018 or statements of cash flows through December 31, 2016.[18] Meanwhile, beginning in 2008 HVI-CC took loans from GLR at an interest rate of 12.5 percent (the money was initially

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[14] TREX US2587 at HVI066334 (Tax Sharing Agreement between Greka Integrated, Inc. [GIT] and Greka Oil & Gas, Inc. [HVI-CC], dated January 15, 2013).

[15] Johnson 30(b)(6) Dep. at 50:8-51:25.

[16] Johnson 30(b)(6) Dep. at 60:12-62:4.

[17] Whalen Dep. at 69:6-19; Johnson 30(b)(6) Dep. at 72:10-22.

[18] TREX US2610 at HVIFIN0002070 and 072, TREX US2662 at HVI084318 and 320, TREX US2588 at HVI065334 and 336, TREX US2619 at HVI065317 and 319, TREX US2620 at HVI076583 and 585, TREX US2673 at HVIFIN0000636 and 638, TREX US2590 at HVI084242 and 244, TREX US3233 at HVI0085664 and 666, TREX US3234 at HVI085675, 677, 679, and 681, TREX US3235 at HVI0885683 and 685 (Consolidated Financial Statements of HVI-CC from 2005 to May 31, 2018).

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lent to GIT,[19] and then loaned on to HVI-CC).[20] As of May 31, 2018, these loans resulted in a total liability to HVI-CC of approximately $77.4 million owed to GIT on loans ultimately sourced from GLR.[21]

26. Mr. Grewal's employment contract with GIT provides him (or a designee of his choosing) with a two percent overriding royalty interest in all of HVI-CC's oil and gas interests.[22] This is a property right that entitles him or his

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[19] TREX US2744 (Credit Agreement between Greka Integrated, Inc. [GIT] and Greka Land Holdings, LLC [GLR], dated June 1, 2008); Grewal 10/11-12/16 Dep. at 266:2-267:3.

[20] Whalen Dep. at 92:20-94:14, 279:13-280:14; TREX US 2619 at HVI065323 (Consolidated Financial Statements of HVI-CC 2011-2012); TREX US2588 at HVI065341 (Consolidated Financial Statements of HVI-CC, 2009-2010); TREX US2662 at HVI084317 (Consolidated Financial Statements of HVI-CC, 2007-2008); Grewal 10/11-12/16 Dep. at 265:15-267:3; TREX US2578 at HVI082440 (First Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016, Schedule 6.01(e) Existing Indebtedness). Note that the interest rate on the 2008 credit agreement with GIT as borrower and GLR as lender is 12.5 percent. (TREX US2744 (Credit Agreement between Greka Integrated, Inc. [GIT] and Greka Land Holdings, LLC, [GLR] dated June 1, 2008). However, GIT's financial statements reported that its note payable-related party bore interest at 12 percent, not 12.5 percent. TREX US2623 at HVI065398 (Consolidated Financial Statements of GIT, 2009-2010). HVI-CC's financial statements indicate that its note payable-related party also carried a12 percent interest rate. TREX US2588 at HVI065341 (Consolidated Financial Statements of HVI-CC, 2009-2010). It is unclear if GIT memorialized its loans to HVI-CC prior to May 20, 2016. Whalen Dep. at 92:20-95:5.

[21] TREX US3235 at HVI085684 (Unaudited Balance Sheets and Income Statements for quarter ending March 31, 2018 and months ending April 30, 2018 and May 31, 2018).

[22] TREX US2525 HVI080022 (Amendment No. 1 of Amended and Restated Executive Employment Agreement by and between Greka Energy Corporation and Randeep S. Grewal, August 20, 2003); TREX US2525 at HVI080023 (Assignment and Assumption of Amended and Restated Executive Employment Agreement

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designee to two percent of production from HVI-CC's oil and gas wells. The designee from at least 2010 to November 2015 was GRL, LLC which formerly was known as Grewal (Royalty), LLC (not to be confused with GLR which I discuss elsewhere in my testimony). HVI-CC paid GRL, LLC over $7.8 million in royalties from 2010 to September 2014.[23]

27. HVI-CC's General Counsel Susan Whalen serves as General Counsel to GIT. Ms. Whalen testified that she also provides legal counsel to a number of entities associated with Mr. Grewal, including GLR and GRL, LLC, as well as Mr. Grewal in his personal capacity. Ms. Whalen does not separately track her time for work on behalf of these entities, and is compensated for all of her legal work on behalf of these entities – including work for Mr. Grewal in his personal capacity and work for GLR and other entities that are not owned by GIT – only by the paycheck she receives from GIT.[24] Ms. Whalen provided legal services to these entities at Mr. Grewal's direction.[25]

28. In addition, HVI-CC's primary customer is GRC, Inc., [26] to which it has also sold oil and gas interests.[27] In 2016, HVI-CC transferred ownership of its

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between Greka Energy Corporation and Greka Integrated, Inc. [GIT], January 1, 2004).

[23] TREX US2663 (Greka Oil & Gas [HVI-CC] Revenue Accounting System Owner Payment History).

[24] Whalen Dep. at 26:21-27:22 and 42:14-25.

[25] Whalen Dep. at 272:3-14.

[26] Grewal 10/11-12/16 Dep. at 276:22-277:5; Johnson 30(b)(6) Dep. at 36:7-9; TREX US2619 at HVI065317 and 323, TREX US2620 at HVI076583 and 589, TREX US2590 at HVI084242 and 249, and TREX US3233 at HVI085664 and 671 (HVI-CC Consolidated Financial Statements Years Ended December 31, 2011-2016).

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subsidiary Rincon Island Limited Partnership to another affiliate without receiving or providing any payment, despite the fact that Rincon Island Limited Partnership entered bankruptcy immediately after the conveyance and the transfer actually removed liabilities from HVI-CC's balance sheet.[28]

29. Many of these transactions would not make financial sense if HVI-CC was managed as an independent company, but can be explained if HVI-CC is managed in concert with its affiliates.

HVI-CC Would Not Be a Viable Operation as a Standalone Company

30. Viewed in isolation, as of the third quarter of 2016, the most recent period for which I had financial information when my February 9, 2017 expert report was submitted, HVI-CC's financial condition had been weak for many years. During that time, the company was heavily indebted, and faced persistent problems in paying its debts as they came due. HVI-CC's auditor rendered a "going concern" opinion for the company in 2014 and 2015, indicating the auditor's doubt about HVI-CC's ability to continue in operation.[29] In May 2016, HVI-CC implemented a major debt restructuring that effectively removed approximately $100 million in liabilities from its balance sheet.[30] But in the

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[27] TREX US2524 at HVI084258 (Action by Unanimous Consent of the Sole Director of HVI Cat Canyon, Inc., November 9, 2015). On November 9, 2015, Randeep Grewal, acting as the sole director of HVI-CC, executed the transfer of Union Sugar 34 well to Greka Refining Company, Inc. [GRC] for $100,000.

[28] TREX US2524 at HVI084277 (Resolutions of the Board of Directors of HVI Cat Canyon, Inc., August 7, 2016); TREX US2524 at HVI084279 (Resolutions of the Board of Directors of HVI Cat Canyon, Inc., August 8, 2016); Grewal 10/11-12/16 Dep. at 261:17-263:19.

[29] TREX US2590 at HVI084238 and TREX US2673 at HVIFIN0000632 (Consolidated Financial Statements of HVI-CC, 2013-2014 and 2014-2015).

[30] TREX US3233 at HVI085671 (Consolidated Financial Statements of HVI-CC,

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immediate wake of the 2016 refinance, with oil prices in the $45-$52/barrel range,[31] HVI-CC still struggled to generate positive cash flow from operations and to pay debts as they came due.[32]

31. Supplemental information provided by HVI-CC since my February 9, 2017 expert report was submitted confirms that HVI-CC's financial condition remained weak through 2016. HVI-CC's auditor again rendered a "going concern" opinion for the company in 2016.[33] Also in 2016, HVI-CC borrowed an additional $6.7 million from its affiliated party, GLR, via GIT.[34] This $6.7 million exactly offset HVI-CC's cash losses from its operations and the cash purchases of property, plant and equipment in 2016.[35] In early 2017, the aggregate principal that could be borrowed on HVI-CC's related party loan from GLR (under which funds

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2016, Notes to Financial Statements). My February 19, 2017 expert report had stated that HVI-CC eliminated "nearly" $100 million in liabilities from its balance sheet. In fact, based on supplemental information produced since July 2018, HVI-CC reported a gain on loan restructure of $112,776,224 in its audited statement of operations for 2016 (TREX US3233 at HVI085664).

[31] Spot prices for Crude Oil in Cushing, Oklahoma, FOB, U.S. Department of Energy, U.S. Energy Information Administration, https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=M, accessed September 13, 2018. Attached as Exhibit E.

[32] Grewal 10/11-12/16 Dep. at 307:9-308:8, 428:4-16.

[33] TREX US3233 at HVI085660 (Consolidated Financial Statements of HVI-CC, 2016).

[34] TREX US3233 at HVI085666 (Consolidated Financial Statements of HVI-CC, 2016, Statement of Cash Flows); Whalen Dep. at 89:1-91:10, 92:20-93:2, 99:23-100:21, 279:13-280:14; Grewal10/11-12/16 Dep. at 266:2-14.

[35] TREX US3233 at HVI085666 (Consolidated Financial Statements of HVI-CC, 2016, Statement of Cash Flows).

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are lent by GLR to GIT, and then lent by GIT to HVI-CC) was raised from $32.5 million to $38.75 million.[36]

32. The unaudited quarterly and monthly balance sheets and income statements recently made available by HVI-CC for 2017 through May 2018 show that the company continues to lose money on a net income basis. HVI-CC reported net income losses of $16.4 million in 2017 and $6.7 million year-to-date through May 2018.[37] As of May 31, 2018, HVI-CC's balance sheet shows total liabilities exceeding total assets by $9.2 million.[38] Finally, in its August 15, 2018 response to the United States' Second Set of Interrogatories, HVI-CC reported that it had state and county tax liens totaling $37.5 million recorded against its assets.[39]

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[36] TREX US3236 at HVI085702 (Resolutions of the Sole Director of HVI Cat Canyon, Inc., January 31, 2017).

[37] TREX US3234 at HVI085675, 677, 679, and 681 (Unaudited Income Statements of HVI-CC, three months ended March 31, June 30, September 30, and December 31, 2017). TREX US3235 at HVI085683 and 685 (Unaudited Balance Sheets and Income Statements for quarter ending March 31, 2018 and months ending April 30, 2018 and May 31, 2018).

[38] HVI-CC's oil and gas assets, before depletion, were valued at $137.1 million on a balance sheet basis as of May 31, 2018. (TREX US3235 at HVI085684, Unaudited Balance Sheets and Income Statements for quarter ending 3/31/2018 and months ending 4/30/2018 and 5/31/2018). This is not the market value of these assets, however. Instead, this valuation reflects HVI-CC's full cost of acquisition, exploration, and development of its oil and gas assets. HVI-CC does not report the depletion associated with its oil and gas assets separate from the depreciation associated with its capital assets; thus, I am unable to report the *net* value of HVI-CC's oil and gas assets on a balance sheet basis.

[39] TREX US3237 (HVI-CC's Supplemental Response to United States' Second Set of Interrogatories, Supplemental Response to Interrogatory No. 13, August 15, 2018).

33. HVI-CC did not provide audited financial statements for 2017 and states through its lawyers that they have not been prepared. This is surprising because since 2006, audited annual financial statements for HVI-CC have always been prepared no later than August 30 of the following year and the most recent audited financial statements made available for the year ended 2016 were prepared in June 2017.[40] Further, HVI-CC's First Lien Credit Agreement with UBS requires that audited financial reports be provided to UBS within 120 days of the end of each fiscal year, meaning that the 2017 financials should have been prepared by May 1, 2018.[41] No statements of cash flows were provided for the period between 2017-2018 until late the night before this Declaration was due to be filed with the Court.[42] Cash flow statements are crucial to have a full understanding of HVI's current financial status. I have not had an opportunity to review these documents and reserve the right to supplement this Declaration, as appropriate.

34. Regardless of HVI-CC's current financial condition, however, because its finances are not managed independently from its affiliates, it is not possible to meaningfully evaluate the company's financial condition independent from its affiliates. For example, HVI-CC's debt obligations today would be far smaller if it had never incurred debt on behalf of GIT in 2005, or if GIT had repaid that debt of $79 million with interest in 2015 under the original terms of the promissory note.

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[40] TREX US2610 at HVIFIN0002067; TREX US2662 at HVI084315, TREX US2588 at HVI065330, TREX US2619 at HVI065313, TREX US2620 at HVI076579, TREX US2673 at HVIFIN0000632, TREX US2590 at HVI084238, TREX US3233at HVI085660 (HVI-CC, Audited Financial Statements, years ended December 31, 2008-2016).

[41] TREX US2578 at HVI082356 (First Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016, Section 5.01).

[42] See, e.g., TREX HVI0099-HVI0101, HVI0128, and HVI0129.

HVI-CC Has Relied on Substantial Loans from an Affiliate

35. In past years, HVI-CC has relied on loans ultimately sourced from an affiliate, GLR,[43] which like HVI-CC, is ultimately controlled by Mr. Grewal.[44] At the times GLR made these loans, HVI-CC would have had difficulty obtaining funds from an unrelated lender due to its poor financial condition and also because its existing credit agreements with unaffiliated lender UBS restrict its ability to take on additional debt.[45] Initially, loans from GLR were made to GIT (HVI-CC's parent corporation) through a 2008 Credit Agreement for $25 million that accrued interest at a rate of 12.5 percent per year, due December 1, 2010.[46] These funds, in turn, were loaned by GIT to HVI-CC.[47] HVI-CC's audited financial statements for

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[43] Whalen Dep. at 92:20-94:14, 279:13-280:14; TREX US 2619 at HVI065323 (Consolidated Financial Statements of HVI-CC 2011-2012); TREX US2588 at HVI065341 (Consolidated Financial Statements of HVI-CC, 2009-2010); TREX US2662 at HVI084317 (Consolidated Financial Statements of HVI-CC, 2007-2008); Grewal 10/11-12/16 Dep. at 265:15-267:3; TREX US2578 at HVI082440 and HVI082354 (First Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016).

[44] Whalen Dep. at 286:17-22; TREX US2744 at HVIFIN0001356 (Credit Agreement dated as of June 1, 2008, Greka Integrated, Inc. [GIT] and Greka Land Holdings, LLC [GLR]).

[45] TREX US2578 at HVI082369-713 (First Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016); US2468 at HVI082608-12 (Second Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016).

[46] TREX US2744 at HVIFIN00013333, HVIFIN0001338 (Credit Agreement dated as of June 1, 2008, Greka Integrated, Inc. [GIT] and Greka Land Holdings, LLC [GLR]); Grewal 10/11-12/16 Dep. at 266:8-14.

[47] Whalen Dep. at 92:20-94:14, 279:13-280:14; TREX US2619 at HVI065316 and 23 (Consolidated Financial Statements of HVI-CC 2011-2012); TREX US2662 at HVI084317 (Consolidated Financial Statements of HVI-CC, 2007-2008); TREX US2588 at HVI065332 (Consolidated Financial Statements of HVI-CC, 2009-

the years ended 2011 and 2012, in fact, refer to the secured related party note payable as resulting from a transaction between HVI-CC and GLR as if a direct debt existed between the two affiliates without GIT as an intermediary.[48] In addition, the credit agreement entered into in May 2016 by HVI-CC and UBS refers to the amount owed by HVI-CC to GIT as related to borrowings under the loan agreement between GLR and GIT.[49] Finally, Mr. Grewal testified that funds loaned to GIT from GLR were then loaned on to HVI-CC.[50]

36. In May 2016, GIT amended its credit agreement with GLR to allow GIT to borrow up to $35 million; in January 2017, this agreement was amended to raise the amount GIT could borrow up to $38.75 million.[51] In connection with this

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2010); Grewal 10/11-12/16 Dep. at 265:15-267:3; TREX US2578 at HVI082440 and HVI082354 (First Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016). It does not appear that GIT memorialized its loans to HVI-CC prior to May 20, 2016. TREX US2425 (Intercmpany [sic] Note between HVI-CC, Rincon Island Limited Partnership, and Greka Integrated, May 20, 2016).

[48] TREX US2619 at HVI065323 (Consolidated Financial Statements of HVI-CC 2011-2012). In addition, the amount owed on the related party note payable between HVI-CC and GLR discussed in HVI-CC's 2011-2012 Consolidated Financial Statements can be tied back to the related party note payable discussed in HVI-CC's prior financial statements. See, TREX US2588 at HVI065333 (Consolidated Financial Statements of HVI-CC, 2009-2010).

[49] TREX US2578 at HVI082440 and HVI082354 (First Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016); TREX US2468 at HVI082592 (Second Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016).

[50] Grewal 10/11-12/16 Dep. at 266:8-14.

[51] TREX US3236 at HVI085701 (Resolutions of the Sole Director of HVI Cat Canyon, Inc., January 31, 2017. HVI-CC has not produced the amended GIT/GLR credit agreement itself, which I am aware of only because it is discussed in this Board of Director's resolution.

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GIT/GLR credit agreement, GIT and HVI-CC entered into an intercompany note in May 2016 that allowed HVI-CC to borrow up to $32.5 million from GIT;[52] in January 2017, this note was amended to allow HVI-CC to borrow up to $38.75 million, mirroring the GIT/GLR credit agreement.[53] In 2016, HVI-CC borrowed an additional $6.7 million in funds ultimately sourced from GLR and used at least $3 million to cover its operating losses.[54] I have not seen any evidence suggesting that GLR will not continue to make loans to HVI-CC and its affiliates as needed to cover expenses as they come due.

37. Since the beginning of 2016, GLR has increased the borrowing capacity of its loan to HVI-CC from $25 million to $38.75 million (via GIT).[55] Of this, $6.7 million has been loaned to HVI-CC.[56] Also in 2016, GLR agreed to provide up to $10 million in debtor-in-possession financing to Rincon Island Limited Partnership, a former subsidiary and current affiliate of HVI-CC, during its

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[52] TREX US 2425 at HVI082276 (Intercmpany [sic] Note between HVI Cat Canyon, Inc., Rincon Island Limited Partnership, and Greka Integrated, May 20, 2016).

[53] TREX US3236 at HVI085702 (Resolutions of the Sole Director of HVI Cat Canyon, Inc., January 31, 2017). HVI-CC has not produced the amended HVI-CC/GIT credit agreement itself, which I am aware of only because it is discussed in this Board of Director's resolution.

[54] Grewal 10/11-12/16 Dep. at 307:9-308:8.

[55] Whalen Dep. at 92:20-94:14; TREX US2425 (Intercmpany [sic] Note between HVI-CC, Rincon Island Limited Partnership, and Greka Integrated, May 20, 2016); TREX US3236 at HVI085702 (Resolutions of the Sole Director of HVI Cat Canyon, Inc., January 31, 2017).

[56] TREX US3233 at HVI085666 (Consolidated Financial Statements of HVI-CC, 2016, Statement of Cash Flows).

pending bankruptcy.[57] Including the increase of HVI-CC's borrowing capacity of $13.75 million (i.e., from $25 million to $38.75 million) and the $10 million in debtor-in-possession financing, GLR has thus provided $23.75 million in potential and actual financing to the GIT group of companies since the beginning of 2016. These loans and loan commitments suggest that GLR has substantial resources and a willingness to loan money to its financially struggling affiliates, which like GLR are under Mr. Grewal's common control.[58] I have not seen evidence that this lending will cease if HVI-CC requires additional funds.

Conclusions Regarding HVI-CC's Financial Condition

38. Based on my analysis, my expert opinions are as follows:

a. HVI-CC has not been managed as if it were a standalone business. Instead, it has been managed in concert with its affiliated entities. I have not seen anything to suggest this practice will change.

b. As of the third quarter of 2016, HVI-CC's financial condition had been weak for many years. In 2016, the company negotiated a major debt restructuring that effectively eliminated approximately $100 million in liabilities from its balance sheet. Even so, HVI-CC recently has relied on funds from an affiliate to remain in operation. Based on the supplemental information provided by the defendant, HVI-CC's

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[57] TREX US3220 at 1 (Rincon Island Limited Partnership Chapter 11in the U.S. Bankruptcy Court for the Northern District of Texas. Agreed Final Order Approving Use of Cash Collateral and Approving Post-Petition Financing); Grewal 10/11-12/16 Dep. at 254:15-255:25.

[58] HVI-CC and GLR have consistently refused to provide direct information regarding GLR and its finances. See Grewal 10/11-12/16 Dep. at 268:16-17, 268:22—270:6, 426:23-427:21; TREX CA5013 (Subpoena to GLR LLC by United States District Court for the Central District of California 10/6/2016).

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financial condition has remained weak from the third quarter of 2016 through May 31, 2018.

c. HVI-CC's affiliate, GLR, LLC, has been able and willing to lend funds that have allowed HVI-CC to continue in operation, including $6.7 million provided to HVI-CC in 2016. GLR's lending and financing practices suggest that it has substantial resources and a willingness to lend to its affiliates. I have not seen anything to suggest this practice will change.

Exhibits To Be Introduced in Support of Direct Testimony

1. TREX US2677: Meyer Economic Benefit Report;
2. The following exhibits relied upon in my Economic Benefit Report:
   a. TREX US2634: Expert Report of Michael L. Kinworthy;
   b. TREX US3214: Appendix D (dated 4/26/17) of Expert Report of Michael L. Kinworthy;
3. TREX US2676: Meyer Financial Condition Report;
4. TREX US2426: Meyer Supplemental Financial Condition Report;
5. The following exhibits relied upon in my Financial Condition Report and/or my Supplemental Financial Condition Report:
   a. TREX US2239: Greka Integrated, Inc. Audited Consolidated Financial Statements, Years ended 12/31/2013;
   b. TREX US2253: Greka Integrated, Inc. Audited Consolidated Financial Statements, Years ended 12/31/2014 & 2013;
   c. TREX US2425: Intercmpany [sic] Note, May 20, 2016;
   d. TREX US2449: Organizational Chart, undated;

e. TREX US2468: Second Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016;

f. TREX US2524: Actions by Board of Directors of HVI Cat Canyon, Inc., February 10, 2015 – August 8, 2016;

g. TREX US2525: Amended and Restated Executive Employment Agreement, dated November 3, 1999, including amendments and assignments;

h. TREX US2578: First Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016;

i. TREX US2583: Greka California organizational chart;

j. TREX US2587: Promissory Note from Greka Integrated, Inc. to Greka Oil & Gas, Inc. dated August 26, 2005;

k. TREX US2588: Greka Oil & Gas and Subsidiary Consolidated Financial Statements Years Ended December 31, 2010 and 2009;

l. TREX US2590: HVI Cat Canyon, Inc. and Subsidiary. Consolidated Financial Statements Years Ended December 31, 2015 and 2014;

m. TREX US2610: Greka Oil & Gas and Subsidiary Consolidated Financial Statements Years Ended December 31, 2006 and 2005;

n. TREX US2619: HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements Years Ended December 31, 2012 and 2011;

o. (TREX US2620: HVI Cat Canyon, Inc. and Subsidiary. Consolidated Financial Statements Years Ended December 31, 2013;

p. TREX US2622: Greka Integrated, Inc. Audited Consolidated Financial Statements, Years ended 12/31/2008 & 2007;

q. TREX US2623: Greka Integrated, Inc. Audited Consolidated Financial Statements, Years ended 12/31/2010 & 2009;

r. TREX US2624: Greka Integrated, Inc. Consolidated Financial Statements, Years Ended December 31, 2012 and 2011;

s. TREX US2662: Greka Oil & Gas and Subsidiary Consolidated Financial Statements Years Ended December 31, 2008 and 2007;

t. TREX US2663: Greka Oil & Gas Revenue Accounting System Owner Payment History. January 2010 to September 2014;

u. TREX US2673: HVI Cat Canyon, Inc. and Subsidiary. Consolidated Financial Statements Years Ended December 31, 2014 and 2013;

v. TREX US2674: HVI Cat Canyon, Inc., Quarterly Financial Statements; Quarters ending Mar, June & Sept, 2015-2016;

w. TREX US2678: Letter from UBS, AG to Greka Oil & Gas, Inc. dated July 28, 2014;

x. TREX US2692: Minutes of Annual Meeting of Board of Directors of Greka Integrated, Inc.;

y. TREX US2693: Minutes of Annual Meeting of Board of Directors of HVI Cat Canyon, Inc.;

z. TREX US2698: Schedule 2 to 2/14/2007 Purchase and Sale Agreement between Greka Oil & Gas, Inc. and UBS, Wire Transfers of Purchase Price;

aa. TREX US2744: Credit Agreement dated June 1, 2008 between Greka Integrated, Inc. and Greka Land Holdings, LLC.;

bb. TREX US2745: Credit Agreement dated August 26, 2005 between Greka Oil & Gas, Inc. and Guggenheim Corporate Funding, LLC.;

cc. TREX US3220: Rincon Island Limited Partnership Chapter 11 bankruptcy in the U.S. Bankruptcy Court for the Northern District of

Texas. Agreed Final Order Approving Use of Cash Collateral and Approving Post-Petition Financing, Document 53;

dd. TREX US3225: 2016 U.S. Corporate Income Tax Returns for GIT, Inc. & Subsidiary;

ee. TREX US3226: 8/17/2017 Oil Rights Agreement between HVI Cat Canyon, Inc. (fka Greka Oil & Gas, Inc.) and Americas Oil and Gas, Inc. (fka Greka AM, Inc.) and the Byron and Ann S. Revocable Trust;

ff. TREX US3227: 10/4/2017 Purchase & Sale Agreement between HVI Cat Canyon, Inc. (fka Greka Oil & Gas, Inc.) and the Grace S. Rocco Living Trust;

gg. TREX US3229: 8/31/2017 Notification of Well and/or Facility Disposition from HVI Cat Canyon, Inc. (fka Greka Oil & Gas, Inc.) to Frank and Sylvia Boisseranc Trust;

hh. TREX US3230: 6/27/2017 Purchase & Sale Agreement between HVI Cat Canyon, Inc. (fka Greka Oil & Gas, Inc.) and Americas Oil and Gas, Inc. (fka Greka AM, Inc.) and El-Yoba Linda, LLC;

ii. TREX US3231: HVI Budget 2017;

jj. TREX US3232: HVI Budget 2018;

kk. TREX US3233: HVI Cat Canyon, Inc., Audited Financial Statements, year ended December 31, 2016;

ll. TREX US3234: HVI Cat Canyon, Inc. Internal Quarterly Financial Statements (Balance Sheet and Income Statement) for quarters ending March, June, September, and December 2017;

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mm. TREX US3235: HVI Cat Canyon, Inc. Internal Quarterly Financial Statements (Balance Sheet and Income Statement) for quarter ending March 2018 and months ending April and May 2018;

nn. TREX US3236: Resolutions of the Sole Director of HVI Cat Canyon, Inc., January 31, 2017;

oo. TREX US3237: HVI Cat Canyon, Inc.'s Supplemental Response to United States' Second Set of Interrogatories, August 15, 2018.

6. The following Exhibits that I prepared as attachment to my Financial Condition Report (TREX US2676):

a. Updated Exhibit 1: HVI Cat Canyon, Inc. Organizational Chart;

b. Updated Exhibit 2: HVI Cat Canyon and Subsidiary Consolidated Balance Sheet;

c. Updated Exhibit 3: HVI Cat Canyon, Inc. and Subsidiary Consolidated Income Statement; and

d. Updated Exhibit 4: HVI Cat Canyon and Subsidiary Consolidated Statement of Cash Flows.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this 14 day of September, 2018, in Cambridge, Massachusetts.

Joan K. Meyer

Joan K. Meyer, Ph.D.

Exhibit A:
Economic Benefit Expert Report

EXPERT REPORT OF DR. JOAN K. MEYER

HVI Cat Canyon, Inc.'s Economic Benefit from Noncompliance

United States et al. v. HVI Cat Canyon, Inc., f/k/a Greka Oil & Gas, Inc.,
CV 11-05097 FMO (SSx) (C.D. Cal.)

Prepared for:
United States Department of Justice
Environment and Natural Resources Division
Environmental Enforcement Section

Signature Joan K. Meyer

Date May-2-2017

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I. SUMMARY OF OPINIONS

I have been retained by the U.S. Department of Justice, representing the Plaintiff, the United States of America (United States), to evaluate the economic benefit, if any, gained by HVI Cat Canyon, Inc. ("HVI-CC"), formerly known as Greka Oil and Gas, Inc. ("Greka"), through non-compliance with the Clean Water Act (CWA), the Oil Pollution Act of 1990, and their implementing regulations, as alleged by the United States. The United States alleges numerous violations from multiple facilities owned and operated by HVI-CC relating to oil spills and other incidents.

It is my opinion, based on widely accepted principles of economics and finance, that HVI-CC gained an economic benefit from its failure to fully comply on a timely basis with regulatory requirements relating to the Clean Water Act and the Oil Pollution Act of 1990. By delaying (in some cases) or avoiding (in other cases) the costs of compliance, HVI-CC gained an economic benefit. I estimate this economic benefit to be **$6.32 million** in net present value terms as of June 20, 2017, the projected trial date in this case.

I may revise my opinions further as additional information becomes available to me. I reserve the right to supplement this Report.

II. BASIS FOR OPINION AND CURRICULUM VITAE

My opinions are based on my education and expertise in economic and financial analysis, experience with economic benefit calculations and in environmental non-compliance cases, independent research for certain publicly available data, communications with the U.S. Department of Justice (DOJ), and inputs from Michael Kinworthy, another expert witness testifying on behalf of the United States in this matter. My calculations are based on a well-established methodology for calculating economic benefit from non-compliance. My opinion is based on widely accepted financial and economic analysis principles.

My resume, testimony history for the last four years, and compensation statement follow the main body of this report in **Appendix A**.

III. ECONOMIC BENEFIT

A. BACKGROUND

The United States alleges that HVI-CC failed to comply with a number of requirements under various regulations of the Clean Water Act and the Oil Pollution Act of 1990.[1] The United States requested that I calculate the economic benefit, if any, from the company's failure to fully comply with the applicable environmental requirements. When a violator such as HVI-CC delays or avoids compliance with environmental requirements, it gains an economic benefit from delaying or avoiding the compliance costs. An economic benefit analysis estimates the amount by which a violator is financially better off from not complying with environmental requirements in a timely manner. The United States alleges that

[1] First Amended Complaint, paragraphs 188, 191, 195, 196, 201, 208, 211, and 214.

HVI-CC failed to comply with numerous requirements across a range of dates. The earliest non-compliance date for the violations considered in my analysis is November 1999.

B. THEORY OF ECONOMIC BENEFIT

Economic benefit estimates the amount by which an entity is better off from one course of action as opposed to another. Economic benefit is "no fault" in nature; an entity need not have deliberately chosen a particular course of action (or its consequences) for it to accrue an economic benefit. In the context of environmental enforcement cases, economic benefit represents the amount of money the violator saved by not undertaking actions that should have been carried out to fully comply on time with all regulatory requirements.

An essential purpose of penalties is to provide incentives to entities to comply with applicable laws and regulations and in so doing, provide deterrence against noncompliance. Gary Becker, the Nobel Prize winning economist, first developed the fundamental economic model for determining the optimal penalty level which shows that potential violators respond to both the probability of detection as well as the severity of punishment, if detected.[2] Penalties, in addition, serve to remove the financial advantage a violator may have gained over compliant entities. By avoiding and/or delaying the costs of compliance, businesses that violate environmental regulations typically enjoy lower operating costs than their competitors. Thus, penalties serve to "level the playing field" by removing these financial advantages. Should a penalty fall short of recovering the violator's economic benefit, not only would it fail to deter the violator in this case, but it may also fail to deter other potential violators. That is, other entities subject to regulation may see an economic advantage in similar noncompliance. For that reason, penalties, in part, attempt to recover economic benefit from noncompliance.

Consistent with EPA's approach for estimating economic benefit, I examine the costs saved by the violator through delayed and/or avoided compliance with environmental requirements.[3] The appropriate economic benefit estimate represents the amount of money that a violator saved by not incurring costs associated with compliance-related actions that should have been taken in order to fully comply on time. If the United States fails to recover through a civil penalty at least this economic benefit, then the violator will retain a gain from its non-compliance. By recapturing the economic benefit realized by the violator as a component of the penalty, the United States "levels the playing field" by ensuring that companies which fully comply on time are not economically worse off than companies that do not. Thus, an economic benefit estimate does not represent compensation to the United States as in a typical "damages" calculation for a tort case, but instead is the minimum amount by which the violator must be penalized so as to return it to the financial position it would have been in had it complied on time. Economic benefit is

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[2] Becker, Gary S., "Crime and Punishment: An Economic Approach," *Journal of Political Economy*, (1968). This model has been extended to civil enforcement, as well. See, for example, Polinsky, A. Mitchell and Steven Shavell, "Enforcement Costs and the Optimal Magnitude and Probability of Fines," *Journal of Law and Economics,* 35 (Apr 1992) 1: 133-148; and Cohen, Mark A., "Monitoring and Enforcement of Environmental Policy," *International Yearbook of Environmental and Resource Economics* (Thomas H. Tietenberg and Henk Folmer eds.), 1999.

[3] Environmental Protection Agency. "Interim Clean Water Act Settlement Penalty Policy." March 1, 1995. https://www.epa.gov/sites/production/files/documents/cwapol.pdf; and Environmental Protection Agency. "Civil Penalty Policy For Section 311(b)(3) and Section 311(j) of the Clean Water Act." August 1998. https://www.epa.gov/sites/production/files/documents/311pen.pdf.

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also one of the factors required to be considered when the Court assesses a civil penalty under the CWA.

I have used information provided by Michael Kinworthy (summarized in **Appendix D** of his report) as my basis for estimating the actions that HVI-CC should have undertaken to comply in a timely fashion.[4] I have made modest changes to the information provided by Mr. Kinworthy to facilitate easier mathematical modeling, specifically, by treating certain recurring costs that should have been incurred once every two years or once every five years as a series of one-time costs. This has no effect on my estimate of economic benefit.

Appendix B to my report contains my detailed calculations.

The information provided by Mr. Kinworthy covers several key components, including:

- Estimated costs that HVI-CC reasonably would have been expected to spend to come into compliance on-time with each of the environmental requirements that the United States asserts HVI-CC violated;
- Estimated dates on which HVI-CC was required to make these expenditures in order to be in full compliance;
- Estimated compliance costs incurred by HVI-CC; and
- Estimated and actual dates on which HVI-CC incurred compliance-related expenditures.

With respect to the cost data, the information provided by Mr. Kinworthy also identifies whether each cost was a capital, one-time, or recurring cost, and the date of the cost estimate. For capital costs, I used published guidance from the Internal Revenue Service (IRS) to calculate the tax effects of depreciation of the assets HVI-CC should have purchased.[5] The details of these calculations are shown in **Appendix B** to my report.

Appendix D of Mr. Kinworthy's report summarizes the information provided by Mr. Kinworthy on which my economic benefit estimates are based. Specifically, it presents the dates of initial non-compliance and actual compliance (if applicable) for each violation as well as the costs that HVI-CC should have incurred for full and timely compliance and the estimated expenditures actually made.

1. Avoided vs. Delayed Costs

It is important to distinguish between "avoided" and "delayed" costs. "Avoided costs" are those expenses associated with required regulatory actions that HVI-CC did not undertake and is not expected to undertake in the future. For example, several of the violations asserted by the United States concern HVI-CC's failure to follow proper protocols for testing, monitoring, and/or recordkeeping (e.g., **Appendix B,** Bell items #3 and 7). Even if HVI-CC begins complying with these requirements in the future, they will not incur any expenses relating to their past non-compliance with these requirements. As another

[4] United States of America and People of the State of California, ex rel. California Department of Fish and Wildlife and California Regional Water Board, Coastal Region, v. HVI Cat Canyon, Inc. f/k/a Greka Oil and Gas, Inc., Case No. CV 11-5097 FMO (SSx), Second Supplemental Expert Report of Michael Kinworthy, April 26, 2017 ("Kinworthy Report"), Appendix D.

[5] United States Department of the Treasury, Internal Revenue Service. "Publication 946: How to Depreciate Property." 1999 – 2015. HVI's assets are depreciated on an accelerated schedule over seven years, consistent with Table B-1, "Table of Class Lives and Recovery Periods," for asset class 13.2, "Exploration for and Production of Petroleum and Natural Gas Deposits."

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example, HVI-CC sold the U-Cal lease in 2009; it therefore cannot undertake any corrective action in the future relating to violations at this lease. The expenditures that HVI-CC should have (but did not) incur to satisfy these regulatory requirements are avoided costs that have accrued as an economic benefit to the company.

In other instances, HVI-CC has taken or can still take actions to bring the company into compliance that it should have undertaken years earlier. For instance, based on information from Mr. Kinworthy, I assume that all of the capital equipment required for secondary containment of the tank battery (e.g., **Appendix B,** Davis Lease item #6) was installed and in compliance as of May 30, 2008. For the Davis Lease item #6, this represents a delay of approximately 5.7 years compared to the on-time compliance date of August 31, 2002. For certain other requirements, again based on information from Mr. Kinworthy, I assume that HVI-CC made other one-time expenditures that were required, but did not do so in a timely fashion; the dates of these expenditures vary. These expenditures are classified as "delayed costs." HVI-CC was able to employ the money it should have spent on these compliance measures for other uses during the time span between the on-time compliance date (when the expenditures should have been made) and the company's actual compliance date (when the expenditures were actually made or would be made). As a result, HVI-CC realized an economic benefit based on the time value of money on these delayed costs.

There are numerous instances in which HVI-CC came into compliance with a specific requirement after a period of non-compliance, but the precise date of compliance is unknown (e.g., **Appendix B,** item #4 for the Los Flores Lease). I rely on the assumptions made by Mr. Kinworthy regarding the date by which HVI-CC should have come into compliance in such instances.

In some cases, HVI-CC currently remains in non-compliance, but could come into compliance in the future (e.g., **Appendix B,** item #5 for the Bell Lease). A key assumption of my analysis is that in all of these cases, HVI-CC will make future expenditures to come into compliance, meaning the associated expenditures are classified as delayed rather than avoided costs. Further, I assume that these expenditures will all be incurred on the anticipated trial date. These are both conservative assumptions (i.e., leading to lower estimates of economic benefit, all other things being equal), compared to alternative assumptions such as that HVI-CC would not incur these expenses at all, or that they would incur them at a later date (since, as I understand, any injunction requiring such expenditures would likely not be imposed until after the trial has concluded).

C. APPROACH

I estimated the economic benefit realized by HVI-CC using a discounted cash flow (DCF) model that compares cash flows the company would have spent had it fully complied on time (i.e., a "full compliance" scenario) with cash flows from an "actual" scenario. DCF analysis is a widely accepted financial methodology used to evaluate investments and businesses and is used to evaluate economic benefit for failure to comply on time with environmental requirements.[6]

The "actual" scenario includes all estimated expenditures HVI-CC has made and will need to make in order to comply with the aforementioned requirements. As discussed above, I rely on information from

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[6] See, for example, Stewart Myers and Richard Brealey, Principles of Corporate Finance, 7th edition (Irwin/McGraw-Hill, NY: 2003), page 34. In addition, this methodology is consistent with that employed by EPA to estimate economic benefit. See EPA's BEN economic benefit model, available at http://www.epa.gov/compliance/civil/econmodels/#ben.

Michael Kinworthy regarding the nature and cost of these expenditures.[7] The "full compliance" scenario presumes that HVI-CC would have complied with regulatory requirements by making the necessary expenditures in a timely fashion (i.e., by the dates of initial non-compliance noted in **Appendix B**), beginning as early as November 1999 (for numerous items, e.g., Escolle Lease items #1-4) and as late as October 2010 (for Bell Lease item #4h). The "full compliance" scenario then evaluates the timing and extent of the estimated expenses associated with all of these actions to determine a total cost of compliance. The difference between the actual scenario and the full compliance scenario represents the economic benefit realized by HVI-CC.

I adjust the cash flows under the "full compliance" and "actual" cost scenarios for differences in timing and tax consequences in order to arrive at after-tax present value of the economic benefit. That is, I account for the effects of corporate income taxes and the depreciation tax shield associated with capital expenditures, as well as for the time value of money, in order to express the estimates in after-tax present value terms as of the trial date, June 20, 2017. Any differences in either the size or timing of cash flows between the "full compliance" and "actual" cost scenarios will factor into the economic benefit calculation. Any cash flows that are equivalent in both magnitude and timing in the two scenarios of cost estimates will cancel out.

In sum, I estimate the economic benefit accruing to HVI-CC as the June 20, 2017 present value of net projected cash outflows under the "full compliance" scenario, less net cash outflows under the "actual" scenario through the following steps:

- First, I estimate cash flows under the "actual" scenario. This includes the total amount that HVI-CC has spent or will need to spend in order to come into compliance. I use the cost estimates and other data provided by Mr. Kinworthy, as summarized in **Appendix B**. To account for the effects of inflation, I use the Chemical Engineering Plant Cost Index to adjust cost estimates from one time period to another.[8]
- Offsetting these cash outflows are avoided federal and state income taxes, which produce a cost savings to the company. For non-depreciable expenses (e.g., labor or maintenance costs), the expenditures lower the company's taxable income in the year in which they were made because such expenditures are tax deductible in the year in which they are incurred. The associated tax consequence simply equals the expense in any year multiplied by the combined federal and state tax rates for that year. I employ the highest corporate income tax brackets for both federal and California taxes. Note that using the *marginal* tax rate rather than the average rate or HVI-CC's observed tax expense is a conservative assumption, in that it lowers the net cost to the company of the required expenditures and thus also lowers my total estimate of economic benefit to HVI-CC.

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[7] Kinworthy report, Appendix D.

[8] See http://www.che.com/pci/. The Plant Cost Index, published monthly in *Chemical Engineering*, reflects equipment, construction labor, buildings, and engineering and supervision associated with process plant construction. Because the components of the compliance costs in this case involve capital equipment and labor related to a chemical processing facility, I believe this is the most appropriate index to use to adjust for inflation. Note, however, because inflation measures (e.g., Producer Price Index, Consumer Price Index) typically move in concert to the same drivers of general inflation, I expect that using an alternative inflation index would not significantly change my economic benefit estimates.

- For equipment purchases, I account for the avoided taxes associated with depreciation expense somewhat differently, because the expense is spread over several years for tax purposes rather than being recognized all at once. For purchases of depreciable assets, the total depreciable base is the same as the value of the asset, as determined by the purchase price. Based on IRS guidance, the equipment involved can be depreciated for tax purposes on an accelerated basis over seven years.[9] In addition, at various points in times, Congress put in place special provisions allowing additional special depreciation allowances of which HVI-CC may have been able to take advantage. At any point in time when such options were available, I assume that HVI-CC would have used the depreciation option that was the most advantageous to it to reduce its tax expense. **Appendix B** shows what special depreciation options were available to HVI-CC in each year.
- The difference between cash outflows from expenditures and inflows from avoided taxes represents the total cash flow that I attribute to the "actual compliance" scenario in any given year.
- Next, I estimate HVI-CC's expenditures under the "on-time" (i.e., "full compliance") scenario. For this scenario, I use the cost estimates, required compliance dates, and other data provided by Mr. Kinworthy, as summarized in **Appendix B**. Just as in the "actual" scenario, to account for the effects of inflation, I use the Chemical Engineering Plant Cost Index to adjust cost estimates from one time period to another.
- My methodology for calculated tax and depreciation effects associated with HVI-CC's "full compliance" expenditures follows the same procedure described above in order to derive the net cash flows under the "full compliance" scenario in any particular year.
- I translate all of these nominal annual cash flows into a single net present value figure as of June 20, 2017, the projected trial date, for each scenario. To do so, I multiply each cash flow by an annual discount rate, compounding the results forward by repeating this process through all subsequent years up through 2017.[10] The discount rate represents the time value of money, i.e., the benefit gained from making a given expenditure later rather than sooner. As discussed below, for the discount rate, I use an estimate of HVI-CC's weighted average cost of capital based on industry figures for oil and gas producers.
- The difference between the net present value as of June 20, 2017 of the net cash flows under the "full compliance" scenario and the net cash flows under the "actual" scenario is the overall economic benefit of non-compliance accruing to HVI-CC as a result of its noncompliance.

While the foregoing discussion has provided a general description of my methods, the detailed calculations underlying my analysis can be found in **Appendix B**.

[9] United States Department of the Treasury, Internal Revenue Service. "Publication 946: How to Depreciate Property," Table B-1, "Table of Class Lives and Recovery Periods," asset class 13.2, "Exploration for and Production of Petroleum and Natural Gas Deposits."1999 – 2015. See also Table A-1, "3-, 5-, 7-, 10-, 15-, and 20-Year Property Half-Year Convention."

[10] For cash flows assumed to occur after 2017 (i.e., related to the tax effects of depreciation expense), I discount the cash flows backwards to 2017.

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D. DATA INPUTS AND ASSUMPTIONS

Appendix B presents the data inputs provided by Mr. Kinworthy. Other key assumptions that apply across all of the regulatory requirements included in this analysis are shown in **Exhibit 1.**

EXHIBIT 1. OTHER KEY ASSUMPTIONS FOR ECONOMIC BENEFIT ESTIMATE

ROW	ECONOMIC BENEFIT ELEMENT	ASSUMPTION
1	Weighted Average Cost of Capital (WACC), 1999 - 2016 (average)	10.13%
2	Date of Actual Compliance (where HVI-CC is currently in noncompliance)	6/20/2017
3	Net Present Value (NPV) Date	6/20/2017
4	Combined Federal & State Marginal Tax Rate	40.75%

Sources:
1. Ibbotson Cost of Capital Yearbook, 1999-2013, and Duff & Phelps Valuation Handbook: Industry Cost of Capital, 2014-2016.
2. Assumed trial date, as provided by DOJ.
3. Assumed trial date, as provided by DOJ.
4. Highest combined marginal rate for U.S. and California corporate income taxes (35% + 8.84% x (1 - 35%) = 40.75%).

E. DISCOUNT RATE

A fundamental principle underlying corporate finance is that a dollar today is preferable to a dollar tomorrow. The process of converting future cash flows into present value terms is termed 'discounting' and the combined effect of factors giving rise to the time value of money is termed the 'discount rate.' The process of converting past cash flows in present value terms is termed 'compounding,' but in general, the numerical factor used to accomplish this is still referred to as the 'discount rate,' a convention I follow here.

In practice, the discount rate is a function of the expected real return (i.e., time value of money), the expected inflation rate (i.e., deterioration in the purchasing power of the cash flow), and the uncertainty associated with the cash flow being discounted. By means of discounting, *nominal* cash flows that are estimated to occur at a different point in time can be expressed in present value terms by use of a discount rate.

I multiply the stream of cash flows from past years by the discount rates for every subsequent year in order to put these flows in terms of a net present value as of the anticipated trial date of June 20, 2017, which I use as the presumed penalty payment date for this case. I then subtract the net present value of the cash flows under the actual scenario to the value of cash flows under the full compliance scenario in order to arrive at an overall estimate of economic benefit.

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In order to adjust for the time value of money, I employ the estimated weighted average cost of capital (WACC) for HVI-CC as the discount rate. The WACC is the most widely-used approach for estimating the discount rate to be used in discounted cash flow analysis.[11]

The WACC represents the return that investors demand from the company in return for their investment. It is premised on the concept that any use of capital imposes an opportunity cost on investors. Funds invested in one option necessarily have been diverted from earning a return on the next-best option. Corporate uses of capital must be benchmarked against the alternative uses that equity investors (e.g., stockholders) and debt investors (e.g., banks, bondholders) face in financial markets. The WACC weights the relative importance of equity capital and debt capital according to their relative contributions to the company's overall funds. At a fundamental level, the WACC represents a firm's cost of doing business – the minimum return that must be generated in order to remain operational over the long term without investors choosing to invest their money elsewhere in investment options that present a better risk-return profile. In the finance field, it is a common and widely-accepted practice to use a company's WACC as a discount rate.[12]

To calculate a company-specific WACC, three basic inputs are needed: (1) the company's after-tax cost of debt; (2) its cost of equity; and (3) the relative proportion of debt and equity in the company's capital structure. These values are typically calculated on at least an annual basis. However, in HVI-CC's case, data limitations and methodological challenges exist with each of these steps:

1. I only had access to HVI-CC's financial statements, which are key sources of information for several inputs into the WACC, for 2005 – 2015. Thus, it would not have been possible to calculate a company-specific WACC in earlier years given the information I had available.
2. From 2010-2013, HVI-CC's long-term debt consisted of a non-interest bearing note payable to a settlement party. From 2010 to 2015, most of or all of HVI-CC's debt consisted of a related-party note payable. These debt instruments likely do not reflect market interest rates based on HVI-CC's creditworthiness, an underlying assumption of the WACC. In addition, in 2007, HVI-CC entered into a Volumetric Production Payment (VPP) agreement in which it essentially forward-sold 4,824,573 barrels of oil yet to be extracted to UBS, a Swiss global financial services company, for $161.5 million.[13] The obligation to produce oil in the future, without any future compensation, creates "unearned revenue" or "deferred revenue" for the seller, which is considered a liability;[14] however, it does not incur an interest charge in the same way as

[11] See, for example, Stewart Myers and Richard Brealey, Principles of Corporate Finance, 7th edition (Irwin/McGraw-Hill, NY: 2003), page 523.

[12] See, for example, Aswath Damodaran, Corporate Finance, 2nd edition, (John Wiley & Sons, NY: 2001), pages 45, 574-595.

[13] TREX US2662, Greka Oil & Gas, Inc. Consolidated Financial Statements, Years Ended December 31, 2008 and 2007. (HVI084312 at HVI084327)

[14] Financial Accounting Standards Board, "Statement of Financial Accounting Standards No. 19," December 1977. Paragraph 47a. Available at http://www.fasb.org/cs/BlobServer?blobkey=id&blobnocache=true&blobwhere=1175820904922&blobheader=application/pdf&blobcol=urldata&blobtable=MungoBlobs. Accessed February 6, 2017.

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traditional debt.[15] Thus, while this transaction provided a substantial portion of HVI-CC's financing, I cannot readily calculate a cost of debt for the funds provided.

3. HVI-CC is a privately held company. Thus, its shares are not traded and a market value of equity is not available. In some cases, it would be possible to use the company's book value of equity instead of its market value of equity. However, from 2013 to 2015, the company had a negative book value of equity (also known as stockholder's equity, or net worth). From a theoretical perspective, if the company had no value to its shareholders, the shareholders would liquidate it. Since this did not happen, HVI-CC clearly provided equity value to its owners. From a mathematical perspective, a negative book value of equity implies that debt makes up over 100 percent of HVI-CC's capital structure, which makes it impossible to provide a clear interpretation of the proportion of debt to equity.

These limitations prevented me from calculating a company-specific WACC for HVI-CC. As a proxy, I therefore used an industry-level WACC for the crude petroleum and natural gas industry (SIC 131), as reported by Ibbotson's (1999-2013) and Duff & Phelps (2014-2016). These sources publish industry-level cost of capital statistics.[16] Specifically, I use the industry median WACC, calculated using the capital asset pricing model. Prior to 2011, I use the median WACC exactly as reported. In 2011 and beyond, Ibbotson's and Duff & Phelps provides additional information on the industry average cost of debt. This allows me to adjust the reported WACC to reflect Greka's specific tax situation (i.e., a combined marginal rate of 40.75%). Note that this is a conservative assumption that slightly lowers my estimate of economic benefit, as compared to simply using the industry average WACC in all years.

Many analysts add in a size premium when estimating a company's cost of capital. This represents the premium that investors demand for investing in smaller companies rather than larger ones, and like the equity risk premium is determined empirically based on a large collection of actual investment data. HVI-CC is sufficiently small that a size premium would arguably be appropriate in this case; however, I do not apply one. This is a conservative approach that reduces my estimate of the company's economic benefit.

Exhibit 2 summarizes the WACC used in my calculations for each year from 1999 – 2016.

E. RESULTS

I estimate that HVI-CC will have realized an economic benefit from non-compliance of **$6,317,199** in net present value as of the anticipated trial date of June 20, 2017. As noted above, all of these calculations account for depreciation and tax effects, and adjust all dollar amounts spent over the time period in question to an equivalent-year basis. HVI-CC thus gained a substantial economic benefit as a result of its noncompliance.

[15] One could consider the implicit interest rate to be determined by the difference between the projected future value of the oil to be delivered, and the value of the up-front cash provided by UBS.

[16] *Ibbotson Cost of Capital Yearbook*. (Standard & Poor's Compustat Data, Chicago IL: annual), SIC Code 131, 1999-2013); and Duff & Phelps *Valuation Handbook: Industry Cost of Capital.* (Standard & Poor's Compustat Data, Chicago IL: annual), SIC Code 131, 2014-2016. Note that Duff & Phelps purchased the business known as "Ibbotson" so the two use the same methodology.

EXHIBIT 2. WEIGHTED AVERAGE COST OF CAPITAL, 1999 - 2016

YEAR	WEIGHTED AVERAGE COST OF CAPITAL
1999	10.49%
2000	11.62%
2001	10.74%
2002	11.29%
2003	9.81%
2004	9.09%
2005	9.01%
2006	9.97%
2007	8.99%
2008	10.95%
2009	13.12%
2010	11.67%
2011	10.32%
2012	9.54%
2013	8.80%
2014	9.35%
2015	8.53%
2016	9.13%
Source: Ibbotson Cost of Capital Yearbook, 1999-2013, and Duff & Phelps Valuation Handbook: Industry Cost of Capital, 2014-2016.	

F. CONSERVATIVE ASSUMPTIONS

There are several ways in which my estimate of economic benefit incorporates conservative assumptions in calculating the economic benefit gained by HVI-CC.

- First, as noted above, I rely on Mr. Kinworthy's estimates concerning the exact date on which HVI-CC came in compliance for delayed costs. To the extent that he conservatively assumes that HVI-CC would have addressed violations shortly after the initial inspection revealed the violation, my economic benefit results, likewise, will be conservative (i.e., lower than they would be otherwise). In addition, as I understand, Mr. Kinworthy has made other conservative assumptions regarding compliance costs and other key inputs, which he has discussed in more detail in his expert report. Because my analysis relies on Mr. Kinworthy's inputs, these additional conservatisms are likewise reflected in my economic benefit estimate.
- Also as noted above, when estimating a company's WACC, many analysts add on a size premium for small companies, to reflect the higher perceived risk associated with investing in those companies. HVI-CC is sufficiently small that a size premium is arguably appropriate in this case. However, rather than taking this approach, I have used the industry average WACC without any size premium. If I had used a size premium, HVI-CC's WACC would be higher, which would in turn increase the net present value of the company's economic benefit as of June 20, 2017.

- Finally, I have treated recurring expenses as costs that should have been expended annually (i.e., once per year), biennially, or every five years on the anniversary of the date of initial non-compliance. In most cases, these dates fall in the second half of the year. Alternatively, I could have assumed that costs were expended on an ongoing basis (i.e., 1/365th of the annual amount incurred daily for annual expenses). The effect of this methodological choice is that in the period from January 1 through June 20, 2017 (the assumed compliance date), my model assumes that HVI-CC should expend costs under the full compliance scenario on only a small proportion of the items classified as recurring expenses. If I had instead assumed that ongoing expenses would have been incurred evenly over time on a daily basis, my estimates would have reflected a larger expense in 2017 in the full compliance scenario, thereby increasing HVI-CC's estimated economic benefit.

Each of these conservatisms highlights the fact that under a range of plausible assumptions, one could produce a higher reported economic benefit than the one I have produced here. My estimate, therefore, should be evaluated in that context as a conservative estimate of HVI-CC's economic benefit.

IV. SUMMARY AND CONCLUSIONS

It is my opinion, based on widely accepted principles of economics and finance, that HVI-CC gained an economic benefit from its failure to fully comply on a timely basis with regulatory requirements relating to the Clean Water Act and the Oil Pollution Act of 1990. By delaying (in some cases) or avoiding (in other cases) the costs of compliance, HVI-CC gained an economic benefit. Overall, I estimate that HVI-CC gained $6.32 million in economic benefit in net present value terms as of the anticipated trial date of June 20, 2017.

I may revise my opinions further as additional information becomes available to me. I reserve the right to supplement this Report.

IEc

INDUSTRIAL ECONOMICS, INCORPORATED

Appendix A

J O A N K . M E Y E R

Dr. Meyer's primary areas of expertise are economic, financial, and policy analysis. As a Principal at Industrial Economics, Incorporated, she has more than 25 years of experience in analyzing the economic, business, and financial dimensions of natural resource and environmental issues. She regularly testifies as an expert witness in federal, state and administrative courts, and supports litigation teams on the economic and financial aspects of cases involving air, water, and hazardous waste issues. Her testimony in these cases has encompassed the financial condition of businesses and individuals, the economic benefit gained by companies from regulatory noncompliance, fraudulent conveyance, successor liability, piercing the corporate veil, de facto mergers, regional economic impact of businesses and industries, and issues relating to cost/benefit analysis. She also assesses the likely impacts of proposed reorganization plans for companies in Chapter 11 bankruptcy.

Dr. Meyer's recent project experience includes the following:

- Directing the development of strategies and approaches to assess the financial condition and corporate performance of businesses, individuals, government and not-for-profit organizations to pay penalties, afford clean-up expenditures and other investments, and meet financial assurance requirements.
- Tracing complex corporate structures, transactions, and financial and corporate operations in matters involving questions about corporate successors, corporate control, piercing the corporate veil, de facto merger, and fraudulent conveyance.
- Estimating the economic benefit gained by violators from noncompliance or delayed compliance with regulatory requirements.
- Conducting training and seminars in corporate financial analysis and related topics.

Dr. Meyer received her B.S. degree in Agricultural and Resource Economics (with honors) from the University of California, Berkeley and her M.S. and Ph.D. degrees from Cornell University (Major field: Environmental and Natural Resource Economics; Minor fields: Corporate Finance and Econometrics/Quantitative Methods). Prior to joining IEc, Dr. Meyer was Senior Associate at The Cadmus Group, Inc., Associate at Putnam, Hayes & Bartlett, Inc., and Research Analyst in the Department of Policy Development and Planning, Governor's Office, State of Alaska. She is a member of the American Economics Association and the Agricultural and Applied Economics Association.

Financial and Economic Analysis

- Assessing the financial condition and ability to pay of corporations, limited liability companies, master limited partnerships, partnerships, sole proprietorships, individuals, and municipalities and other public entities to afford environmental expenditures, penalties and/or fines.
- Estimating the economic benefits gained from delayed and/or avoided compliance by violators in the hardrock mining, real estate development, natural gas, petroleum, meat processing, agriculture, coal, timber, wood products, and other industries with applicable environmental and other regulations.
- Tracing the corporate successors to owners and operators by analyzing corporate and financial records of mergers, asset purchase agreements, reorganizations, and other complex business transactions.
- Providing expert financial analysis of businesses in Chapter 11 bankruptcy protection for companies in the battery, coal, oil & gas, aluminum, chemical, hazardous and non-hazardous waste disposal, hard rock mining, and specialty metals industries. Analyzing the corporate history and organizational structure, the ability of companies to successfully restructure their operations while adequately providing for their environmental liabilities, and the viability of alternative financial responsibility proposals.
- Assessing the financial assurance mechanisms for companies with significant financial assurance responsibilities under the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation, and Liability Act, and /or the Surface Mining Control and Reclamation Act that were operating under Chapter 11 bankruptcy protection.
- Evaluating the corporate, financial, and organizational behavior of groups of affiliated businesses in order to determine the extent to which the affiliates adhere to corporate norms and are managed as independent entities.
- Leading the assessment of the financial gain realized by a pipeline operator from failure to appropriately maintain, upgrade, and monitor its system.
- Directing the financial analysis of inability to pay claims by Potentially Responsible Parties at more than 200 Superfund sites.
- Conducting the evaluation of the financial status and operation of businesses, individuals, and not-for-profit organizations involved in environmental enforcement actions.
- Estimating the economic benefit realized by a major defense contractor from the accounting treatment of site remediation costs in rates charged under government contracts.
- Estimating the economic benefits realized by a major aerospace company through the voluntary participation in government programs.
- Managing litigation support activities in a case involving a mining operation and its relationship to its corporate owners. Conducting detailed analysis of the aspects of a parent-subsidiary operating relationship over more than four decades as it pertained to norms of typical corporate behavior and various elements of corporate control.

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Testimony within the Past Four Years

- In the matter of PPG Industries Inc. v. United States of America (U.S. District Court, District Court of New Jersey), provided deposition testimony about economic benefit gained by PPG Industries from the sites at issue in the litigation.
- In the matter of In re: Alpha Natural Resources, Inc. (U.S. Bankruptcy Court for the Eastern District of Virginia, Richmond Division), provided deposition testimony about the likely financial viability of the reorganization plan proposed for a coal company over the next five years including its ability to meet its reclamation and other environmental liabilities.
- In the matter of Harris County, Texas and the Texas Commission on Environmental Quality v. International Paper Company, et al. (District Court of Harris County, Texas), provided trial and deposition testimony about the corporate successors to a paper mill and the company that disposed of waste from the mill in the 1960s and the associated penalties.
- In the matter of Lockheed Martin v. United States of America (U.S. District Court, District of Columbia), provided trial and deposition testimony about Lockheed's recovery of remediation costs incurred at a Superfund site through overhead charges under its contracts with the United States and the economic benefit that would be gained by Lockheed from an additional CERCLA payment from the United States.
- In the matter of the United States of America and the South Carolina Department of Health and Environmental Control v. Albemarle Corporation (U.S. District Court, District of South Carolina), provided deposition testimony about the economic benefit gained by the defendant from noncompliance with Clean Air Act regulations.
- In the matter of the United States of America v. Federal Resources Corporation, et al. (U.S. District Court, District of Idaho), provided deposition testimony about the related parties to the defendants and the financial and corporate impact of a particular transaction in a case concerning CERCLA cost recovery.
- In the matter of the United States of America and the State of Nebraska v. STABL, Inc. (U.S. District Court, District of Nebraska), provided trial testimony about the economic benefit gained by the defendant from noncompliance with Clean Water Act regulations.
- In the matter of the United States of America v. ConAgra Grocery Products Company, LLC (U.S. District Court, District of Maine), provided deposition testimony regarding the corporate successors to former operators at a particular facility.
- In the matter of the United States of America v. Hamilton (U.S. District Court, District of Wyoming), provided deposition testimony about the economic benefit gained by the defendants from noncompliance with the Clean Water Act regulations.
- In the matter of TDY Holdings, LLC and TDY Industries, Inc. v. United States of America, United States Department of Defense, and Robert M. Gates (U.S. District Court, Southern District of California), provided trial and deposition testimony on the economic benefits gained by the plaintiffs and their predecessors at their San Diego facility as a result of transactions with military and other federal agencies.

Expert Testimony Rate

Case Preparation Rate, $214 per hour

Testimony Rate, $250 per hour

APPENDIX B | DETAILED CALCULATIONS

				On-time (Full) Compliance					Actual Compliance					
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Type of cost (capital, one-time, annual)	Cost estimate	Date of cost estimate	Depreciab e life, years (capital costs only)	Avoided or delayed cost	Date of actual compliance expenditure ("Avoided through" date for recurring costs)	Type of cost (annual, capital, one-time)	Cost estimate (delayed costs only)	Date of cost estimate	Depreciab e life, years (capital costs only)
1	Williams B	1	Greka has not identified the location of all active and idle flow lines at the Williams B facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	6/30/2000	One-time	$15,000	12/31/2002	N/A	avoided	N/A	One-time	N/A	N/A	N/A
2	Williams B	2	There is no regular program of flow line maintenance for each flow line at Williams B to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	6/30/2000	Biennial	$100,000	12/31/2002	N/A	avoided	2/25/2010	Biennial	N/A	N/A	N/A
3	Williams B	3	The facility did not have a SPCC Plan at the time of the USEPA inspection on March 21, 2008.	6/30/2000	One-time	$5,000	12/31/2002	N/A	avoided	N/A	One-time	N/A	N/A	N/A
4	Williams B	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	6/30/2000	Annual	$1,200	12/31/2002	N/A	avoided	2/25/2010	Annual	N/A	N/A	N/A
5	Williams B	5	The secondary containment around the tanks and production equipment was not present or were compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	6/30/2000	Capital	$2,000	12/31/2002	7	delayed	3/19/2008	Capital	$2,000	12/31/2002	7
6	Lloyd	1	Greka has not identified the location of all active and idle flow lines at the Lloyd facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	8/31/2002	One-time	$2,000	12/31/2002	N/A	delayed	8/1/2010	One-time	$2,000	12/31/2002	N/A
7	Lloyd	2	No SPCC Plan was available for the Lloyd facility.	8/31/2002	One-time	$5,000	12/31/2002	N/A	delayed	1/28/2011	One-time	$5,000	12/31/2002	N/A
8	Lloyd	3	Tanks were observed with significant corrosion at the Lloyd facility. Decommission the tanks or replace. (40 CFR 112.2, API 653, and API 12R1)	8/31/2002	One-time	$1,500	12/31/2002	N/A	delayed	4/27/2007	One-time	$1,500	12/31/2002	N/A
9	Lloyd	4	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	8/31/2002	Capital	$1,200	12/31/2002	7	delayed	6/29/2007	Capital	$1,200	12/31/2002	7
10	Lakeview	1	Greka has not identified the location of all active and idle flow lines at the Lakeview facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	8/31/2002	One-time	$38,250	12/31/2002	N/A	delayed	8/1/2010	One-time	$38,250	12/31/2002	N/A
11	Lakeview	2	The 2007 SPCC Plan for the Lakeview Lease did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - facility does not have a program for flow line maintenance (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	8/31/2002	One-time	$5,000	12/31/2002	N/A	delayed	6/29/2007	One-time	$5,000	12/31/2002	N/A
12	Lakeview	3	Two tanks were observed outside of secondary containment at the Lakeview facility.	8/31/2002	Capital	$2,000	12/31/2002	7	delayed	6/29/2007	Capital	$2,000	12/31/2002	7
13	Lakeview	4	Multiple tanks at Lakeview facility are deteriorated and identified as out of service but still contain some product in them. (540 CFR 112.2, API 653, and API 12R1).	8/31/2002	One-time	$1,500	12/31/2002	N/A	delayed	4/27/2007	One-time	$1,500	12/31/2002	N/A
14	Lakeview	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	8/31/2002	Capital	$1,200	12/31/2002	7	delayed	6/29/2007	Capital	$1,200	12/31/2002	7

Appendix B: Cost Inputs

Row	Lease	Item No.	Item Description	On-time (Full) Compliance: Date of initial non-compliance	Type of cost (capital, one-time, annual)	Cost estimate	Date of cost estimate	Depreciable life, years (capital costs only)	Actual Compliance: Avoided or delayed cost	Date of actual compliance expenditure ("Avoided through" date for recurring costs)	Type of cost (annual, capital, one-time)	Cost estimate (delayed costs only)	Date of cost estimate	Depreciab e life, years (capital costs only)
15	Los Flores	1	The 2004 SPCC Plan for Los Flores did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - facility does not have a program for flow line maintenance (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	8/31/2002	One-time	$5,000	12/31/2002	N/A	delayed	4/8/2011	One-time	$5,000	12/31/2002	N/A
16	Los Flores	2	Greka has not identified the location of all active and idle flow lines at the Los Flores facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, SPI 579-1, and ASME FFS-1)	8/31/2002	One-time	$7,750	12/31/2002	N/A	delayed	8/1/2010	One-time	$7,750	12/31/2002	N/A
17	Los Flores	3	There is no regular program of flow line maintenance for each flow line at Los Flores to reduce the likelihood of a discharge. (40 CFR 112.1b, 112,7e, and 112,9d and API 570)	8/31/2002	Every 5 years	$32,500	12/31/2002	N/A	Avoided	5/20/2010	Every 5 years	N/A	N/A	N/A
18	Los Flores	4	Multiple tanks are deteriorated and identified as out of service but still contain some product in them. (40 CFR 112.2, API 653, and API12R1 require facilities to ensure containers are not used for storage unless the material used and conditions of storage are compatible.)	8/31/2002	One-time	$1,500	12/31/2002	N/A	Delayed	4/27/2007	One-time	$1,500	12/31/2002	N/A
19	Los Flores	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	Delayed	6/29/2007	capital	$1,200	12/31/2002	7
20	Los Flores	6	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	Annual	$1,200	12/31/2002	N/A	Avoided	6/20/2017	Annual	N/A	N/A	N/A
21	Los Flores	7	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c)	8/31/2002	capital	$1,200	12/31/2002	7	delayed	6/20/2017	capital	$1,200	12/31/2002	7
22	Bell	1	The SPCC Plan did not comply with the following regulatory requirements of 40 CFR 112. - no signature of management approval (112.7(a) and 112.5(a)) (Bates EPA9_0032601) - no signature by Registered Professional Engineer (112.3(d) and 112.5(c)) (Bates EPA9_0032601) - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - inadequately details the inspection, testing, and recordkeeping protocols (40 CFR 112.7d). - inadequately details oil production facility bulk storage containers (40 CFR 112.9d, API 653, API 12R1, and STI SP001). - facility does not have a program of flowline maintenance (40 CFR 112.9d, API 570, and ASME B31.3). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	11/30/1999	one-time	$5,000	12/31/2002	N/A	delayed	4/7/2011	one-time	$5,000	12/31/2002	N/A
23	Bell	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include n a regular inspection program. (40 CFR 112.9d, API 570, API 579-a, and ASME FFS-1)	11/30/1999	one-time	$33,500	12/31/2002	N/A	delayed	8/1/2010	one-time	$33,500	12/31/2002	N/A

				On-time (Full) Compliance					Actual Compliance						
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Type of cost (capital, one-time, annual)	Cost estimate	Date of cost estimate	Depreciab e life, years (capital costs only)	Avoided or delayed cost	Date of actual compliance expenditure ("Avoided through" date for recurring costs)	Type of cost (annual, capital, one-time)	Cost estimate (delayed costs only)	Date of cost estimate	Depreciab e life, years (capital costs only)
24	Bell	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.)	11/30/1999	Every 5 years	$212,500	12/31/2002	N/A	Avoided	1/11/2010	Every 5 years	N/A	N/A	N/A
25	Bell	4a	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	6/8/2005	one-time	$2,500	12/31/2002	N/A	Avoided	N/A	one-time	N/A	N/A	N/A
26	Bell	4b	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	7/13/2005	one-time	$2,500	12/31/2002	N/A	Avoided	N/A	one-time	N/A	N/A	N/A
27	Bell	4c	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	8/11/2005	one-time	$2,500	12/31/2002	N/A	Avoided	N/A	one-time	N/A	N/A	N/A
28	Bell	4d	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	7/16/2007	one-time	$2,500	12/31/2002	N/A	Avoided	N/A	one-time	N/A	N/A	N/A
29	Bell	4f	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	1/29/2008	one-time	$2,500	12/31/2002	N/A	Avoided	N/A	one-time	N/A	N/A	N/A
30	Bell	4g	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	5/1/2009	one-time	$2,500	12/31/2002	N/A	Avoided	N/A	one-time	N/A	N/A	N/A
31	Bell	4h	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	10/14/2010	one-time	$2,500	12/31/2002	N/A	Avoided	N/A	one-time	N/A	N/A	N/A
32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	11/30/1999	capital	$1,200	12/31/2002	7	delayed	6/20/2017	capital	$1,200	12/31/2002	7
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	11/30/1999	Capital	$1,200	12/31/2002	7	delayed	2/29/2008	Capital	$1,200	12/31/2002	7
34	Bell	7	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	Annual	$1,200	12/31/2002	N/A	avoided	6/20/2017	Annual	N/A	N/A	N/A
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	12/7/2007	capital	$4,000	12/31/2002	7	delayed	1/7/2008	capital	$4,000	12/31/2002	7
36	Chamberlin	1	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	8/31/2002	one-time	$1,750	12/31/2002	N/A	delayed	8/1/2010	one-time	$1,750	12/31/2002	N/A
37	Chamberlin	2	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	Every 5 years	$17,500	12/31/2002	N/A	avoided	2/17/2011	Every 5 years	N/A	N/A	N/A
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	delayed	6/20/2017	capital	$1,200	12/31/2002	7
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	delayed	2/5/2008	capital	$1,200	12/31/2002	7

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				On-time (Full) Compliance					Actual Compliance					
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Type of cost (capital, one-time, annual)	Cost estimate	Date of cost estimate	Depreciab e life, years (capital costs only)	Avoided or delayed cost	Date of actual compliance expenditure ("Avoided through" date for recurring costs)	Type of cost (annual, capital, one-time)	Cost estimate (delayed costs only)	Date of cost estimate	Depreciab e life, years (capital costs only)
40	Chamberlin	5	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	Annual	$1,200	12/31/2002	N/A	Avoided	6/20/2017	Annual	N/A	N/A	N/A
41	Davis	1	The SPCC Plan did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - inadequately details the inspections, testing, and recordkeeping protocols (40 CFR 112.7e). - inadequately details oil production facility bulk storage containers (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - facility does to have a program of flowline maintenance (40 CFR 112.9d, API 570, and ASME B31.3). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	8/31/2002	one-time	$5,000	12/31/2002	N/A	delayed	4/7/2011	one-time	$5,000	12/31/2002	N/A
42	Davis	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include n a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1).	8/31/2002	one-time	$19,000	12/31/2002	N/A	delayed	8/1/2010	one-time	$19,000	12/31/2002	N/A
43	Davis	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 2 flow lines identified in Pipeline Management Plan.	8/31/2002	Biennial	$5,000	12/31/2002	N/A	avoided	3/9/2011	Biennial	N/A	N/A	N/A
44	Davis	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 28 other lines.	8/31/2002	Every 5 years	$70,000	12/31/2002	N/A	Avoided	3/9/2011	Every 5 years	N/A	N/A	N/A
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	delayed	6/20/2017	capital	$1,200	12/31/2002	7
46	Davis	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	delayed	5/30/2008	capital	$1,200	12/31/2002	7
47	Davis	7	Failure of the automatic shut-off alarms and valves on the 3,000 barrel produced water tank created an oil spill and it left the tank battery due to the failure of the secondary containment. After repair the alarm requires to be tested. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	12/7/2005	One-time	$1,200	12/31/2002	N/A	avoided	N/A	One-time	N/A	N/A	N/A

Row	Lease	Item No.	Item Description	On-time (Full) Compliance: Date of initial non-compliance	Type of cost (capital, one-time, annual)	Cost estimate	Date of cost estimate	Depreciable life, years (capital costs only)	Actual Compliance: Avoided or delayed cost	Date of actual compliance expenditure ("Avoided through" date for recurring costs)	Type of cost (annual, capital, one-time)	Cost estimate (delayed costs only)	Date of cost estimate	Depreciab e life, years (capital costs only)
48	Davis	8	A spill event occurred on 1/5/08 with the release of approximately 240,000 gallons of crude oil and produced water from the overfilling of the wash tank. Alarm must be tested after repair. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	1/5/2008	one-time	$1,200	12/31/2002	N/A	avoided	N/A	one-time	N/A	N/A	N/A
49	Davis	9	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	Annual	$1,200	12/31/2002	N/A	avoided	6/20/2017	Annual	N/A	N/A	N/A
50	Casmalia	1	The SPCC Plan did not comply with the regulatory requirements of 40 CFR 112.10 to address onshore oil drilling and workover facilities. In addition, the SPCC Plan has numerous corrective actions to be completed. Plan had a professional engineer evaluation of 2002 even though the plan was dated 2008.	11/30/1999	One-time	$5,000	12/31/2002	N/A	delayed	4/7/2011	One-time	$5,000	12/31/2002	N/A
51	Casmalia	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	11/30/1999	One-time	$20,750	12/31/2002	N/A	delayed	8/1/2010	One-time	$20,750	12/31/2002	N/A
52	Casmalia	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 1 line in environmentally sensitive area (ESA).	11/30/1999	Biennial	$2,500	12/31/2002	N/A	Avoided	7/18/2011	Biennial	N/A	N/A	N/A
53	Casmalia	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 35 other lines.	11/30/1999	Every 5 years	$87,500	12/31/2002	N/A	Avoided	7/18/2011	Every 5 years	N/A	N/A	N/A
54	Casmalia	5	Secondary containment of the tank battery was compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	11/30/1999	capital	$1,200	12/31/2002	7	delayed	3/12/2008	capital	$1,200	12/31/2002	7
55	Casmalia	6	Secondary containment of the wastewater pond was observed to be in a poor condition. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	11/30/1999	capital	$1,200	12/31/2002	7	delayed	3/12/2008	capital	$1,200	12/31/2002	7
56	Casmalia	7	The Santa Barbara County Fire Department tested the alarm system at the tank battery which failed. Greka should perform regular tests on the alarm system to ensure its proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	2/12/2008	Annual	$1,200	12/31/2002	N/A	avoided	6/20/2017	Annual	N/A	N/A	N/A

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Appendix B: Cost Inputs

				On-time (Full) Compliance					Actual Compliance					
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Type of cost (capital, one-time, annual)	Cost estimate	Date of cost estimate	Depreciab e life, years (capital costs only)	Avoided or delayed cost	Date of actual compliance expenditure ("Avoided through" date for recurring costs)	Type of cost (annual, capital, one-time)	Cost estimate (delayed costs only)	Date of cost estimate	Depreciab e life, years (capital costs only)
57	Security	1	The 2004 and 2008 SPCC Plans did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - inadequately details the inspections, testing, and recordkeeping protocols (40 CFR 112.7e). - inadequately details oil production facility bulk storage containers (40 CFR 112.9(c), API 653, API 12R1, and STI SP001). - facility does not have a program of flow line maintenance (40 CFR 112.9(d), API 570, and ASME B31.3). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	8/31/2002	One-time	$5,000	12/31/2002	N/A	delayed	1/28/2011	One-time	$5,000	12/31/2002	N/A
58	Security	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9.(d), API 570, API 579-1, and ASME FFS-1)	8/31/2002	One-time	$23,000	12/31/2002	N/A	delayed	8/1/2010	One-time	$23,000	12/31/2002	N/A
59	Security	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge (i.e., integrity of flow lines at the Waste Oil Tank and around the LCR tanks appeared compromised due to erosion and neglect at time of EPA inspection in 2008). (40 CFR 112.1b, 40 CFR 112.7(e), 40 CFR 112.9(d), and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flow line.)	8/31/2002	Every 5 years	$82,500	12/31/2002	N/A	Avoided	6/10/2009	Every 5 years	N/A	N/A	N/A
60	Security	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires to provide appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	delayed	6/20/2017	capital	$1,200	12/31/2002	7
61	Security	5	Greka stored kerosene distillate (KD) to increase the viscosity of the heavy crude produced at the Security Lease. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. (40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contained spill oil.)	8/31/2002	capital	$10,000	12/31/2002	7	delayed	6/20/2017	capital	$10,000	12/31/2002	7
62	Security	6	Multiple tanks are deteriorated and identified as out of service but still contain some product in them. (40 CFR 112.2, API 653, and API 12R1 require facilities to ensure containers are not used for storage unless the material used and conditions of storage are compatible.)	8/31/2002	One-time	$1,500	12/31/2002	N/A	Delayed	3/12/2008	One-time	$1,500	12/31/2002	N/A
63	Security	7	The secondary containment around the LCR tanks and Waste Oil Tank are compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. An inspection of the Pumper's Weekly Lease Inspection forms were reviewed and these items were not identified in any of the past inspections by the pumper dating back to 2005. (40 CFR 112.7c require appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	Delayed	3/12/2008	capital	$1,200	12/31/2002	7
64	Security	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	Annual	$1,200	12/31/2002	N/A	Avoided	6/20/2017	Annual	N/A	N/A	N/A

				On-time (Full) Compliance					Actual Compliance						
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Type of cost (capital, one-time, annual)	Cost estimate	Date of cost estimate	Depreciabe life, years (capital costs only)	Avoided or delayed cost	Date of actual compliance expenditure ("Avoided through" date for recurring costs)	Type of cost (annual, capital, one-time)	Cost estimate (delayed costs only)	Date of cost estimate	Depreciab e life, years (capital costs only)
65	U-Cal	1	The SPCC Plan did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage control (40 CFR 112.7c and STI SP001). - inadequately details the inspections, testing, and recordkeeping protocols (40 CFR 112.7e). - inadequately details oil production facility bulk storage containers (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - facility does not have a program of flowline maintenance (40 CFR 112.9d, API 570, and ASME B31.3). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	8/31/2002	One-time	$5,000	12/31/2002	N/A	avoided	N/A	One-time	N/A	N/A	N/A
66	U-Cal	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-a, and ASME FFS-1)	8/31/2002	One-time	$31,500	12/31/2002	N/A	Avoided	N/A	One-time	N/A	N/A	N/A
67	U-Cal	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	Every 5 years	$102,500	12/31/2002	N/A	avoided	1/1/2009	Every 5 years	N/A	N/A	N/A
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	avoided	N/A	capital	N/A	N/A	7
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	avoided	N/A	capital	N/A	N/A	7
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	1/13/2005	capital	$10,000	12/31/2002	7	avoided	N/A	capital	N/A	N/A	7
71	U-Cal	7	Per 40 CFR 112.9(c)(3), tanks should be covered under the inspection program per the SPCC plan or properly taken out of service. Several tanks were in deteriorating condition and secondary containment was failing. Either decommission the tanks or repair the tanks and test for integrity.	10/25/2005	One-time	$1,500	12/31/2002	N/A	avoided	N/A	One-time	N/A	N/A	N/A
72	U-Cal	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	Annual	$1,200	12/31/2002	N/A	avoided	1/1/2009	Annual	N/A	N/A	N/A
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	10/25/2005	capital	$1,200	12/31/2002	7	avoided	N/A	capital	N/A	N/A	7
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	2/12/2008	capital	$2,000	12/31/2002	7	avoided	N/A	capital	N/A	N/A	7
75	Escolle	1	Greka has not identified the location of all active and idle flow lines at the Escolle facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	11/30/1999	One-time	$7,500	12/31/2002	N/A	delayed	8/1/2010	One-time	$7,500	12/31/2002	N/A

Row	Lease	Item No.	Item Description	On-time (Full) Compliance: Date of initial non-compliance	Type of cost (capital, one-time, annual)	Cost estimate	Date of cost estimate	Depreciabe life, years (capital costs only)	Actual Compliance: Avoided or delayed cost	Date of actual compliance expenditure ("Avoided through" date for recurring costs)	Type of cost (annual, capital, one-time)	Cost estimate (delayed costs only)	Date of cost estimate	Depreciab e life, years (capital costs only)
76	Escolle	2	There is no regular program of flow line maintenance for each flow line at Lakeview to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	11/30/1999	Every 5 years	$27,500	12/31/2002	N/A	avoided	3/23/2010	Every 5 years	N/A	N/A	N/A
77	Escolle	3	The 2007 SPCC Plan for the Escolle Lease did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - facility does not have a program for flow line maintenance (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	11/30/1999	One-time	$5,000	12/31/2002	N/A	delayed	4/7/2011	One-time	$5,000	12/31/2002	N/A
78	Escolle	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to property identify problems requiring correction at the facility.)	11/30/1999	Annual	$1,200	12/31/2002	N/A	Avoided	6/20/2017	Annual	N/A	N/A	N/A
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	2/12/2008	Capital	$1,200	12/31/2002	7	delayed	3/12/2008	Capital	$1,200	12/31/2002	7
80	Battles	1	The 2004 and 2008 SPCC Plans did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - inadequately details the inspections, testing, and recordkeeping protocols (40 CFR 112.7e). - inadequately details oil production facility bulk storage containers (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - facility does not have a program of flow line maintenance (40 CFR 112.9d, API 570, and ASME B21.3). - does not address onshore drilling and workover facilities (40 CFR 112.10).	11/30/1999	One-time	$5,000	12/31/2002	N/A	delayed	5/5/2011	One-time	$5,000	12/31/2002	N/A
81	Battles	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	11/30/1999	One-time	$14,250	12/31/2002	N/A	delayed	8/1/2010	One-time	$14,250	12/31/2002	N/A
82	Battles	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 3 lines in environmentally sensitive areas (ESA).	11/30/1999	Biennial	$7,500	12/31/2002	N/A	avoided	2/22/2010	Biennial	N/A	N/A	N/A
83	Battles	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 23 other lines.	11/30/1999	Every 5 years	$57,500	12/31/2002	N/A	avoided	2/22/2010	Every 5 years	N/A	N/A	N/A
84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	11/30/1999	capital	$1,200	12/31/2002	7	delayed	6/20/2017	capital	$1,200	12/31/2002	7

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				On-time (Full) Compliance					Actual Compliance					
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Type of cost (capital, one-time, annual)	Cost estimate	Date of cost estimate	Depreciab e life, years (capital costs only)	Avoided or delayed cost	Date of actual compliance expenditure ("Avoided through" date for recurring costs)	Type of cost (annual, capital, one-time)	Cost estimate (delayed costs only)	Date of cost estimate	Depreciab e life, years (capital costs only)
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	11/30/1999	capital	$1,200	12/31/2002	7	delayed	3/12/2008	capital	$1,200	12/31/2002	7
86	Battles	7	Tank UO 903 should be identified as "out of service", have all piping disconnected, open the hatches, and remove all liquids. A new tank should be installed to replace the deteriorated tank. (40 CFR 112.2, API 653, and API 12R1 require facilities to ensure containers are not used for storage unless the material used and conditions of storage are compatible.)	1/12/2005	One-time	$1,500	12/31/2002	N/A	delayed	1/1/2014	One-time	$1,500	12/31/2002	N/A
87	Battles	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	Annual	$1,200	12/31/2002	N/A	Avoided	6/20/2017	Annual	N/A	N/A	N/A

Sources and notes:

(1) All inputs, unless otherwise specified, from the Second Supplemental Expert Report of Michael Kinworthy, April 26, 2017, Appendix D ("Kinworthy expert report")

(2) Where no information was provided in the Kinworthy expert report regarding compliance expenditures, this model assumes for calculation purposes that compliance will be achieved on the assumed trial date, June 20, 2017.

(3) For some recurring costs, HVI began periodic inspection or testing programs. For those claims, avoided annual costs are calculated from the lease start date ("Date of initial non-compliance") to the date of first test ("Date of actual compliance expenditure") rather than from the lease start date to the assumed trial date.

(4) To maintain consistency with the Kinworthy expert report, the numbering of items for the Bell lease omits #4e.

Appendix B: Other Inputs

Row	Discount rates	Industry WACC	PV multiplier
1	1999	10.49%	5.42
2	2000	11.62%	4.91
3	2001	10.74%	4.39
4	2002	11.29%	3.97
5	2003	9.81%	3.57
6	2004	9.09%	3.25
7	2005	9.01%	2.98
8	2006	9.97%	2.73
9	2007	8.99%	2.48
10	2008	10.95%	2.28
11	2009	13.12%	2.05
12	2010	11.67%	1.82
13	2011	10.32%	1.63
14	2012	9.54%	1.47
15	2013	8.80%	1.35
16	2014	9.35%	1.24
17	2015	8.53%	1.13
18	2016	9.13%	1.04
19	*2017*	*9.13%*	*0.95*
20	**Average from 1999 - 2016:**	**10.13%**	
21			
22	**NPV date**	6/20/2017	
23			
24	**Taxes**		
25	California corporate tax rate	8.84%	
26	Federal corporate tax rate	35%	
27	Combined tax rate	40.75%	
28			
29	**Use accelerated depreciation?**	Yes	

Adjust WACC for California Combined Tax Rate

	Pre-tax cost of debt	*Tax rate*	*After-tax cost of debt*	*Cost of equity*	*Debt weight*	*Equity weight*	*Adjusted WACC*
2011	4.60%	40.75%	2.73%	12.30%	20.67%	79.33%	10.32%
2012	7 23%	40.75%	4.28%	11.61%	28.32%	71.68%	9 54%
2013	5.67%	40.75%	3.36%	11.57%	33.70%	66.30%	8 80%
2014	5.40%	40.75%	3.20%	11.10%	22.20%	77.80%	9 35%
2015	4 50%	40.75%	2.67%	10.70%	27.00%	73.00%	8 53%
2016	7 50%	40.75%	4.44%	11.40%	32.60%	67.40%	9.13%

Notes by row:

1-20 For 1999-2010, industry median weighted average cost of capital for the crude petroleum and natural gas industry (SIC Code: 131). For 2011-2016, WACC calculated using California combined tax rate [row 27], industry median cost of debt, cost of equity, and debt-equity weights. The WACC calculation is equal to [debt weight]*[pre-tax cost of debt]*(1-[combined tax rate]) + [equity weight]*[cost of equity]. This calculation is not done in prior years due to data limitations. 2017 set equal to 2016 calculated value. Sources: Ibbotson Cost of Capital Yearbook. (Standard & Poor’s Compustat Data, Chicago IL: annual), SIC Code 131, 1999-2013); and Duff & Phelps Valuation Handbook: Industry Cost of Capital. (Standard & Poor’s Compustat Data, Chicago IL: annual), SIC Code 131, 2014-2016. Note that Duff & Phelps purchased the business known as “Ibbotson,” so the methodological approaches are the same between the two.

22 Assumed per instruction from DOJ.

25 Marginal corporate tax rate, California, as reported by the Tax Foundation, accessed October 31, 2016 at: http://taxfoundation.org/article/state-corporate-income-tax-rates

26 Top marginal corporate tax rate, United States, as reported by the Tax Foundation, accessed at: http://taxfoundation.org/article/corporate-income-tax-rates-around-world-2016

27 [25] + [26] x (100% - [25])

29 Switch to turn accelerated depreciation (double declining balance method under the IRS General Depreciation System) on/off. If accelerated depreciation is not used, straight-line depreciation over the life of the asset is used instead. Note that this switch does not affect special depreciation allowances taken in the first year of a capital cost. For more information, see "Depreciation" tab.

Appendix B: Results

	Present Value as of trial date:	June 20, 2017
1	On-time capital costs	$151,641
2	On-time one-time costs	$801,286
3	Actual capital costs	$64,544
4	Actual one-time costs	$345,467
5	Avoided recurring costs	$5,774,283
6	**Economic benefit at penalty payment date = [1]+[2]-[3]-[4]+[5]**	$6,317,199

Notes by row:

1 Sum of all on-time capital costs, net of depreciation and tax effects, expressed in NPV as of trial date. Source: "On-time scenario" worksheet, row 5.

2 Sum of all on-time one-time costs, net of tax effects, expressed in NPV as of NPV date. Source: "On-time scenario" worksheet, row 10.

3 Sum of all actual capital costs, net of depreciation and tax effects, expressed in NPV as of NPV date. Source: "Actual Scenario" worksheet, row 5.

4 Sum of all actual one-time costs, net of tax effects, expressed in NPV as of NPV date. Source: "Actual Scenario" worksheet, row 10.

5 Sum of all avoided recurring costs, expressed in NPV as of NPV date. Source: "On-time Scenario" worksheet, row 15.

6 Calculated as: row 1 + row 2 - row 3 - row 4 + row 5.

A	B	C	D	E	F	G	H	I	J	K	L
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Type of cost (capital, one-time, annual)	Cost estimate	Date of cost estimate	Depreciable life, years (capital costs only)	Compliance year	On-time compliance cost estimate as of date of initial non-compliance	On-time compliance cost estimate as of end of initial non-compliance year
1	Williams B	1	Greka has not identified the location of all active and idle flow lines at the Williams B facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	6/30/2000	One-time	$15,000	12/31/2002	N/A	2000	$14,812	$15,653
2	Williams B	2	There is no regular program of flow line maintenance for each flow line at Williams B to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	6/30/2000	Biennial	$100,000	12/31/2002	N/A	2000	$98,744	$104,355
3	Williams B	3	The facility did not have a SPCC Plan at the time of the USEPA inspection on March 21, 2008.	6/30/2000	One-time	$5,000	12/31/2002	N/A	2000	$4,937	$5,218
4	Williams B	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	6/30/2000	Annual	$1,200	12/31/2002	N/A	2000	$1,185	$1,252
5	Williams B	5	The secondary containment around the tanks and production equipment was not present or were compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	6/30/2000	Capital	$2,000	12/31/2002	7	2000	$1,975	$2,087
6	Lloyd	1	Greka has not identified the location of all active and idle flow lines at the Lloyd facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	8/31/2002	One-time	$2,000	12/31/2002	N/A	2002	$2,004	$2,077
7	Lloyd	2	No SPCC Plan was available for the Lloyd facility.	8/31/2002	One-time	$5,000	12/31/2002	N/A	2002	$5,010	$5,192
8	Lloyd	3	Tanks were observed with significant corrosion at the Lloyd facility. Decommission the tanks or replace. (40 CFR 112.2, API 653, and API 12R1)	8/31/2002	One-time	$1,500	12/31/2002	N/A	2002	$1,503	$1,558
9	Lloyd	4	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	8/31/2002	Capital	$1,200	12/31/2002	7	2002	$1,202	$1,246
10	Lakeview	1	Greka has not identified the location of all active and idle flow lines at the Lakeview facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	8/31/2002	One-time	$38,250	12/31/2002	N/A	2002	$38,327	$39,722
11	Lakeview	2	The 2007 SPCC Plan for the Lakeview Lease did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - facility does not have a program for flow line maintenance (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	8/31/2002	One-time	$5,000	12/31/2002	N/A	2002	$5,010	$5,192
12	Lakeview	3	Two tanks were observed outside of secondary containment at the Lakeview facility.	8/31/2002	Capital	$2,000	12/31/2002	7	2002	$2,004	$2,077
13	Lakeview	4	Multiple tanks at Lakeview facility are deteriorated and identified as out of service but still contain some product in them. (540 CFR 112.2, API 653, and API 12R1).	8/31/2002	One-time	$1,500	12/31/2002	N/A	2002	$1,503	$1,558

Appendix B: On-time

A	B	C	D	E	F	G	H	I	J	K	L
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Type of cost (capital, one-time, annual)	Cost estimate	Date of cost estimate	Depreciable life, years (capital costs only)	Compliance year	On-time compliance cost estimate as of date of initial non-compliance	On-time compliance cost estimate as of end of initial non-compliance year
14	Lakeview	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	8/31/2002	Capital	$1,200	12/31/2002	7	2002	$1,202	$1,246
15	Los Flores	1	The 2004 SPCC Plan for Los Flores did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - facility does not have a program for flow line maintenance (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	8/31/2002	One-time	$5,000	12/31/2002	N/A	2002	$5,010	$5,192
16	Los Flores	2	Greka has not identified the location of all active and idle flow lines at the Los Flores facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, SPI 579-1, and ASME FFS-1)	8/31/2002	One-time	$7,750	12/31/2002	N/A	2002	$7,766	$8,048
17	Los Flores	3	There is no regular program of flow line maintenance for each flow line at Los Flores to reduce the likelihood of a discharge. (40 CFR 112.1b, 112,7e, and 112,9d and API 570)	8/31/2002	Every 5 years	$32,500	12/31/2002	N/A	2002	$32,565	$33,751
18	Los Flores	4	Multiple tanks are deteriorated and identified as out of service but still contain some product in them. (40 CFR 112.2, API 653, and API12R1 require facilities to ensure containers are not used for storage unless the material used and conditions of storage are compatible.)	8/31/2002	One-time	$1,500	12/31/2002	N/A	2002	$1,503	$1,558
19	Los Flores	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	2002	$1,202	$1,246
20	Los Flores	6	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	Annual	$1,200	12/31/2002	N/A	2002	$1,202	$1,246
21	Los Flores	7	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c)	8/31/2002	capital	$1,200	12/31/2002	7	2002	$1,202	$1,246

Appendix B: On-time

A	B	C	D	E	F	G	H	I	J	K	L
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Type of cost (capital, one-time, annual)	Cost estimate	Date of cost estimate	Depreciable life, years (capital costs only)	Compliance year	On-time compliance cost estimate as of date of initial non-compliance	On-time compliance cost estimate as of end of initial non-compliance year
22	Bell	1	The SPCC Plan did not comply with the following regulatory requirements of 40 CFR 112. - no signature of management approval (112.7(a) and 112.5(a)) (Bates EPA9_0032601) - no signature by Registered Professional Engineer (112.3(d) and 112.5(c)) (Bates EPA9_0032601) - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - inadequately details the inspection, testing, and recordkeeping protocols (40 CFR 112.7d). - inadequately details oil production facility bulk storage containers (40 CFR 112.9d, API 653, API 12R1, and STI SP001). - facility does not have a program of flowline maintenance (40 CFR 112.9d, API 570, and ASME B31.3). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	11/30/1999	one-time	$5,000	12/31/2002	N/A	1999	$4,922	$4,964
23	Bell	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include n a regular inspection program. (40 CFR 112.9d, API 570, API 579-a, and ASME FFS-1)	11/30/1999	one-time	$33,500	12/31/2002	N/A	1999	$32,978	$33,259
24	Bell	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.)	11/30/1999	Every 5 years	$212,500	12/31/2002	N/A	1999	$209,191	$210,970
25	Bell	4a	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	6/8/2005	one-time	$2,500	12/31/2002	N/A	2005	$2,928	$3,074
26	Bell	4b	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	7/13/2005	one-time	$2,500	12/31/2002	N/A	2005	$2,901	$3,020
27	Bell	4c	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	8/11/2005	one-time	$2,500	12/31/2002	N/A	2005	$2,899	$2,998
28	Bell	4d	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	7/16/2007	one-time	$2,500	12/31/2002	N/A	2007	$3,352	$3,487
29	Bell	4f	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	1/29/2008	one-time	$2,500	12/31/2002	N/A	2008	$3,333	$3,667
30	Bell	4g	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	5/1/2009	one-time	$2,500	12/31/2002	N/A	2009	$3,197	$3,472
31	Bell	4h	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	10/14/2010	one-time	$2,500	12/31/2002	N/A	2010	$3,493	$3,577
32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	11/30/1999	capital	$1,200	12/31/2002	7	1999	$1,181	$1,191
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	11/30/1999	Capital	$1,200	12/31/2002	7	1999	$1,181	$1,191

Appendix B: On-time

A	B	C	D	E	F	G	H	I	J	K	L
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Type of cost (capital, one-time, annual)	Cost estimate	Date of cost estimate	Depreciable life, years (capital costs only)	Compliance year	On-time compliance cost estimate as of date of initial non-compliance	On-time compliance cost estimate as of end of initial non-compliance year
34	Bell	7	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	Annual	$1,200	12/31/2002	N/A	1999	$1,181	$1,191
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	12/7/2007	capital	$4,000	12/31/2002	7	2007	$5,275	$5,305
36	Chamberlin	1	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	8/31/2002	one-time	$1,750	12/31/2002	N/A	2002	$1,754	$1,817
37	Chamberlin	2	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	Every 5 years	$17,500	12/31/2002	N/A	2002	$17,535	$18,173
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	2002	$1,202	$1,246
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	2002	$1,202	$1,246
40	Chamberlin	5	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	Annual	$1,200	12/31/2002	N/A	2002	$1,202	$1,246
41	Davis	1	The SPCC Plan did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - inadequately details the inspections, testing, and recordkeeping protocols (40 CFR 112.7e). - inadequately details oil production facility bulk storage containers (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - facility does to have a program of flowline maintenance (40 CFR 112.9d, API 570, and ASME B31.3). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	8/31/2002	one-time	$5,000	12/31/2002	N/A	2002	$5,010	$5,192
42	Davis	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include n a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1).	8/31/2002	one-time	$19,000	12/31/2002	N/A	2002	$19,038	$19,731
43	Davis	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 2 flow lines identified in Pipeline Management Plan.	8/31/2002	Biennial	$5,000	12/31/2002	N/A	2002	$5,010	$5,192

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44	Davis	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 28 other lines.	8/31/2002	Every 5 years	$70,000	12/31/2002	N/A	2002	$70,141	$72,694
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	2002	$1,202	$1,246
46	Davis	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	2002	$1,202	$1,246
47	Davis	7	Failure of the automatic shut-off alarms and valves on the 3,000 barrel produced water tank created an oil spill and it left the tank battery due to the failure of the secondary containment. After repair the alarm requires to be tested. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	12/7/2005	One-time	$1,200	12/31/2002	N/A	2005	$1,436	$1,444
48	Davis	8	A spill event occurred on 1/5/08 with the release of approximately 240,000 gallons of crude oil and produced water from the overfilling of the wash tank. Alarm must be tested after repair. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	1/5/2008	one-time	$1,200	12/31/2002	N/A	2008	$1,600	$1,772
49	Davis	9	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	Annual	$1,200	12/31/2002	N/A	2002	$1,202	$1,246
50	Casmalia	1	The SPCC Plan did not comply with the regulatory requirements of 40 CFR 112.10 to address onshore oil drilling and workover facilities. In addition, the SPCC Plan has numerous corrective actions to be completed. Plan had a professional engineer evaluation of 2002 even though the plan was dated 2008.	11/30/1999	One-time	$5,000	12/31/2002	N/A	1999	$4,922	$4,964
51	Casmalia	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	11/30/1999	One-time	$20,750	12/31/2002	N/A	1999	$20,427	$20,601
52	Casmalia	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 1 line in environmentally sensitive area (ESA).	11/30/1999	Biennial	$2,500	12/31/2002	N/A	1999	$2,461	$2,482

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53	Casmalia	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 35 other lines.	11/30/1999	Every 5 years	$87,500	12/31/2002	N/A	1999	$86,137	$86,870
54	Casmalia	5	Secondary containment of the tank battery was compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	11/30/1999	capital	$1,200	12/31/2002	7	1999	$1,181	$1,191
55	Casmalia	6	Secondary containment of the wastewater pond was observed to be in a poor condition. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	11/30/1999	capital	$1,200	12/31/2002	7	1999	$1,181	$1,191
56	Casmalia	7	The Santa Barbara County Fire Department tested the alarm system at the tank battery which failed. Greka should perform regular tests on the alarm system to ensure its proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	2/12/2008	Annual	$1,200	12/31/2002	N/A	2008	$1,627	$1,783
57	Security	1	The 2004 and 2008 SPCC Plans did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - inadequately details the inspections, testing, and recordkeeping protocols (40 CFR 112.7e). - inadequately details oil production facility bulk storage containers (40 CFR 112.9(c), API 653, API 12R1, and STI SP001). - facility does not have a program of flow line maintenance (40 CFR 112.9(d), API 570, and ASME B31.3). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	8/31/2002	One-time	$5,000	12/31/2002	N/A	2002	$5,010	$5,192
58	Security	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9.(d), API 570, API 579-1, and ASME FFS-1)	8/31/2002	One-time	$23,000	12/31/2002	N/A	2002	$23,046	$23,885
59	Security	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge (i.e., integrity of flow lines at the Waste Oil Tank and around the LCR tanks appeared compromised due to erosion and neglect at time of EPA inspection in 2008). (40 CFR 112.1b, 40 CFR 112.7(e), 40 CFR 112.9(d), and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flow line.)	8/31/2002	Every 5 years	$82,500	12/31/2002	N/A	2002	$82,666	$85,675
60	Security	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires to provide appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	2002	$1,202	$1,246

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61	Security	5	Greka stored kerosene distillate (KD) to increase the viscosity of the heavy crude produced at the Security Lease. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. (40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contained spill oil.)	8/31/2002	capital	$10,000	12/31/2002	7	2002	$10,020	$10,385
62	Security	6	Multiple tanks are deteriorated and identified as out of service but still contain some product in them. (40 CFR 112.2, API 653, and API 12R1 require facilities to ensure containers are not used for storage unless the material used and conditions of storage are compatible.)	8/31/2002	One-time	$1,500	12/31/2002	N/A	2002	$1,503	$1,558
63	Security	7	The secondary containment around the LCR tanks and Waste Oil Tank are compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. An inspection of the Pumper's Weekly Lease Inspection forms were reviewed and these items were not identified in any of the past inspections by the pumper dating back to 2005. (40 CFR 112.7c require appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	2002	$1,202	$1,246
64	Security	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	Annual	$1,200	12/31/2002	N/A	2002	$1,202	$1,246
65	U-Cal	1	The SPCC Plan did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage control (40 CFR 112.7c and STI SP001). - inadequately details the inspections, testing, and recordkeeping protocols (40 CFR 112.7e). - inadequately details oil production facility bulk storage containers (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - facility does not have a program of flowline maintenance (40 CFR 112.9d, API 570, and ASME B31.3). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	8/31/2002	One-time	$5,000	12/31/2002	N/A	2002	$5,010	$5,192
66	U-Cal	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-a, and ASME FFS-1)	8/31/2002	One-time	$31,500	12/31/2002	N/A	2002	$31,563	$32,712
67	U-Cal	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	Every 5 years	$102,500	12/31/2002	N/A	2002	$102,706	$106,445
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	2002	$1,202	$1,246

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69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	8/31/2002	capital	$1,200	12/31/2002	7	2002	$1,202	$1,246
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	1/13/2005	capital	$10,000	12/31/2002	7	2005	$11,688	$12,702
71	U-Cal	7	Per 40 CFR 112.9(c)(3), tanks should be covered under the inspection program per the SPCC plan or properly taken out of service. Several tanks were in deteriorating condition and secondary containment was failing. Either decommission the tanks or repair the tanks and test for integrity.	10/25/2005	One-time	$1,500	12/31/2002	N/A	2005	$1,782	$1,811
72	U-Cal	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	Annual	$1,200	12/31/2002	N/A	2002	$1,202	$1,246
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	10/25/2005	capital	$1,200	12/31/2002	7	2005	$1,426	$1,449
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	2/12/2008	capital	$2,000	12/31/2002	7	2008	$2,712	$2,972
75	Escolle	1	Greka has not identified the location of all active and idle flow lines at the Escolle facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	11/30/1999	One-time	$7,500	12/31/2002	N/A	1999	$7,383	$7,446
76	Escolle	2	There is no regular program of flow line maintenance for each flow line at Lakeview to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	11/30/1999	Every 5 years	$27,500	12/31/2002	N/A	1999	$27,072	$27,302
77	Escolle	3	The 2007 SPCC Plan for the Escolle Lease did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - facility does not have a program for flow line maintenance (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	11/30/1999	One-time	$5,000	12/31/2002	N/A	1999	$4,922	$4,964
78	Escolle	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to property identify problems requiring correction at the facility.)	11/30/1999	Annual	$1,200	12/31/2002	N/A	1999	$1,181	$1,191
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	2/12/2008	Capital	$1,200	12/31/2002	7	2008	$1,627	$1,783

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Row	Lease	Item No.	Item Description	Date of initial non-compliance	Type of cost (capital, one-time, annual)	Cost estimate	Date of cost estimate	Depreciable life, years (capital costs only)	Compliance year	On-time compliance cost estimate as of date of initial non-compliance	On-time compliance cost estimate as of end of initial non-compliance year
80	Battles	1	The 2004 and 2008 SPCC Plans did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - inadequately details the inspections, testing, and recordkeeping protocols (40 CFR 112.7e). - inadequately details oil production facility bulk storage containers (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - facility does not have a program of flow line maintenance (40 CFR 112.9d, API 570, and ASME B21.3). - does not address onshore drilling and workover facilities (40 CFR 112.10).	11/30/1999	One-time	$5,000	12/31/2002	N/A	1999	$4,922	$4,964
81	Battles	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	11/30/1999	One-time	$14,250	12/31/2002	N/A	1999	$14,028	$14,147
82	Battles	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 3 lines in environmentally sensitive areas (ESA).	11/30/1999	Biennial	$7,500	12/31/2002	N/A	1999	$7,383	$7,446
83	Battles	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 23 other lines.	11/30/1999	Every 5 years	$57,500	12/31/2002	N/A	1999	$56,604	$57,086

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84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	11/30/1999	capital	$1,200	12/31/2002	7	1999	$1,181	$1,191
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	11/30/1999	capital	$1,200	12/31/2002	7	1999	$1,181	$1,191
86	Battles	7	Tank UO 903 should be identified as "out of service", have all piping disconnected, open the hatches, and remove all liquids. A new tank should be installed to replace the deteriorated tank. (40 CFR 112.2, API 653, and API 12R1 require facilities to ensure containers are not used for storage unless the material used and conditions of storage are compatible.)	1/12/2005	One-time	$1,500	12/31/2002	N/A	2005	$1,753	$1,906
87	Battles	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	Annual	$1,200	12/31/2002	N/A	1999	$1,181	$1,191

Notes by Column:

[A] - [J]	Reproduced from "Cost Inputs" table.
[K]	Cost estimates in [G] are adjusted for inflation to the initial non-compliance date [E] using the Plant Cost Index (PCI). Equal to [column G] * [PCI as of date in column E] / [PCI as of date in column H].
[L]	Using the year-specific WACC as the discount rate, [column K] is converted to net present value (NPV) as of the end of the initial non-compliance year. Equal to [column K] * (1 + WACC)^(portion of year between initial non-compliance date and Dec. 31 of that year). See "Other inputs" worksheet for year-specific WACC values.

Appendix B: Actual

A	B	C	D	E	F	G	H	I	J	K	L	M
Row	**Lease**	**Item No.**	**Item Description**	**Avoided or delayed cost**	**Date of actual compliance expenditure**	**Type of cost (annual, capital, one-time)**	**Cost estimate (delayed costs only)**	**Date of cost estimate**	**Depreciable life, years (capital costs only)**	**Compliance year**	**Actual compliance cost estimate as of date of actual compliance**	**Actual compliance cost estimate as of end of actual compliance year**
1	Williams B	1	Greka has not identified the location of all active and idle flow lines at the Williams B facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	avoided	N/A	One-time	N/A	N/A	N/A	N/A	$0	$0
2	Williams B	2	There is no regular program of flow line maintenance for each flow line at Williams B to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	avoided	2/25/2010	Biennial	N/A	N/A	N/A	2010	$0	$0
3	Williams B	3	The facility did not have a SPCC Plan at the time of the USEPA inspection on March 21, 2008.	avoided	N/A	One-time	N/A	N/A	N/A	N/A	$0	$0
4	Williams B	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	avoided	2/25/2010	Annual	N/A	N/A	N/A	2010	$0	$0
5	Williams B	5	The secondary containment around the tanks and production equipment was not present or were compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	delayed	3/19/2008	Capital	$2,000	12/31/2002	7	2008	$2,759	$2,993
6	Lloyd	1	Greka has not identified the location of all active and idle flow lines at the Lloyd facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	delayed	8/1/2010	One-time	$2,000	12/31/2002	N/A	2010	$2,761	$2,890
7	Lloyd	2	No SPCC Plan was available for the Lloyd facility.	delayed	1/28/2011	One-time	$5,000	12/31/2002	N/A	2011	$7,094	$7,767
8	Lloyd	3	Tanks were observed with significant corrosion at the Lloyd facility. Decommission the tanks or replace. (40 CFR 112.2, API 653, and API 12R1)	delayed	4/27/2007	One-time	$1,500	12/31/2002	N/A	2007	$1,994	$2,114
9	Lloyd	4	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	delayed	6/29/2007	Capital	$1,200	12/31/2002	7	2007	$1,606	$1,677
10	Lakeview	1	Greka has not identified the location of all active and idle flow lines at the Lakeview facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	delayed	8/1/2010	One-time	$38,250	12/31/2002	N/A	2010	$52,797	$55,280
11	Lakeview	2	The 2007 SPCC Plan for the Lakeview Lease did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - facility does not have a program for flow line maintenance (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	delayed	6/29/2007	One-time	$5,000	12/31/2002	N/A	2007	$6,691	$6,989

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12	Lakeview	3	Two tanks were observed outside of secondary containment at the Lakeview facility.	delayed	6/29/2007	Capital	$2,000	12/31/2002	7	2007	$2,676	$2,796
13	Lakeview	4	Multiple tanks at Lakeview facility are deteriorated and identified as out of service but still contain some product in them. (540 CFR 112.2, API 653, and API 12R1).	delayed	4/27/2007	One-time	$1,500	12/31/2002	N/A	2007	$1,994	$2,114
14	Lakeview	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	delayed	6/29/2007	Capital	$1,200	12/31/2002	7	2007	$1,606	$1,677
15	Los Flores	1	The 2004 SPCC Plan for Los Flores did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - facility does not have a program for flow line maintenance (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	delayed	4/8/2011	One-time	$5,000	12/31/2002	N/A	2011	$7,313	$7,858
16	Los Flores	2	Greka has not identified the location of all active and idle flow lines at the Los Flores facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, SPI 579-1, and ASME FFS-1)	delayed	8/1/2010	One-time	$7,750	12/31/2002	N/A	2010	$10,697	$11,201
17	Los Flores	3	There is no regular program of flow line maintenance for each flow line at Los Flores to reduce the likelihood of a discharge. (40 CFR 112.1b, 112,7e, and 112,9d and API 570)	Avoided	5/20/2010	Every 5 years	N/A	N/A	N/A	2010	$0	$0
18	Los Flores	4	Multiple tanks are deteriorated and identified as out of service but still contain some product in them. (40 CFR 112.2, API 653, and API12R1 require facilities to ensure containers are not used for storage unless the material used and conditions of storage are compatible.)	Delayed	4/27/2007	One-time	$1,500	12/31/2002	N/A	2007	$1,994	$2,114
19	Los Flores	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	Delayed	6/29/2007	capital	$1,200	12/31/2002	7	2007	$1,606	$1,677
20	Los Flores	6	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	Avoided	6/20/2017	Annual	N/A	N/A	N/A	2017	$0	$0
21	Los Flores	7	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c)	delayed	6/20/2017	capital	$1,200	12/31/2002	7	2017	$1,660	$1,739

Appendix B: Actual

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22	Bell	1	The SPCC Plan did not comply with the following regulatory requirements of 40 CFR 112. - no signature of management approval (112.7(a) and 112.5(a)) (Bates EPA9_0032601) - no signature by Registered Professional Engineer (112.3(d) and 112.5(c)) (Bates EPA9_0032601) - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - inadequately details the inspection, testing, and recordkeeping protocols (40 CFR 112.7d). - inadequately details oil production facility bulk storage containers (40 CFR 112.9d, API 653, API 12R1, and STI SP001). - facility does not have a program of flowline maintenance (40 CFR 112.9d, API 570, and ASME B31.3). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	delayed	4/7/2011	one-time	$5,000	12/31/2002	N/A	2011	$7,313	$7,860
23	Bell	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include n a regular inspection program. (40 CFR 112.9d, API 570, API 579-a, and ASME FFS-1)	delayed	8/1/2010	one-time	$33,500	12/31/2002	N/A	2010	$46,240	$48,415
24	Bell	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.)	Avoided	1/11/2010	Every 5 years	N/A	N/A	N/A	2010	$0	$0
25	Bell	4a	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	Avoided	N/A	one-time	N/A	N/A	N/A	N/A	$0	$0
26	Bell	4b	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	Avoided	N/A	one-time	N/A	N/A	N/A	N/A	$0	$0
27	Bell	4c	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	Avoided	N/A	one-time	N/A	N/A	N/A	N/A	$0	$0
28	Bell	4d	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	Avoided	N/A	one-time	N/A	N/A	N/A	N/A	$0	$0
29	Bell	4f	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	Avoided	N/A	one-time	N/A	N/A	N/A	N/A	$0	$0
30	Bell	4g	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	Avoided	N/A	one-time	N/A	N/A	N/A	N/A	$0	$0
31	Bell	4h	Perform integrity tests of flow lines if necessary based on inspections and after a release is detected. (40 CFR 112.9d)	Avoided	N/A	one-time	N/A	N/A	N/A	N/A	$0	$0

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32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	delayed	6/20/2017	capital	$1,200	12/31/2002	7	2017	$1,660	$1,739
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	delayed	2/29/2008	Capital	$1,200	12/31/2002	7	2008	$1,627	$1,775

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34	Bell	7	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	avoided	6/20/2017	Annual	N/A	N/A	N/A	2017	$0	$0
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	delayed	1/7/2008	capital	$4,000	12/31/2002	7	2008	$5,332	$5,904
36	Chamberlin	1	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	delayed	8/1/2010	one-time	$1,750	12/31/2002	N/A	2010	$2,416	$2,529
37	Chamberlin	2	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	avoided	2/17/2011	Every 5 years	N/A	N/A	N/A	2011	$0	$0
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	delayed	6/20/2017	capital	$1,200	12/31/2002	7	2017	$1,660	$1,739
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	delayed	2/5/2008	capital	$1,200	12/31/2002	7	2008	$1,627	$1,787
40	Chamberlin	5	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	Avoided	6/20/2017	Annual	N/A	N/A	N/A	2017	$0	$0
41	Davis	1	The SPCC Plan did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - inadequately details the inspections, testing, and recordkeeping protocols (40 CFR 112.7e). - inadequately details oil production facility bulk storage containers (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - facility does to have a program of flowline maintenance (40 CFR 112.9d, API 570, and ASME B31.3). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	delayed	4/7/2011	one-time	$5,000	12/31/2002	N/A	2011	$7,313	$7,860
42	Davis	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include n a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1).	delayed	8/1/2010	one-time	$19,000	12/31/2002	N/A	2010	$26,226	$27,459

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43	Davis	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 2 flow lines identified in Pipeline Management Plan.	avoided	3/9/2011	Biennial	N/A	N/A	N/A	2011	$0	$0
44	Davis	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 28 other lines.	Avoided	3/9/2011	Every 5 years	N/A	N/A	N/A	2011	$0	$0
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	delayed	6/20/2017	capital	$1,200	12/31/2002	7	2017	$1,660	$1,739
46	Davis	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	delayed	5/30/2008	capital	$1,200	12/31/2002	7	2008	$1,760	$1,871
47	Davis	7	Failure of the automatic shut-off alarms and valves on the 3,000 barrel produced water tank created an oil spill and it left the tank battery due to the failure of the secondary containment. After repair the alarm requires to be tested. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	avoided	N/A	One-time	N/A	N/A	N/A	N/A	$0	$0
48	Davis	8	A spill event occurred on 1/5/08 with the release of approximately 240,000 gallons of crude oil and produced water from the overfilling of the wash tank. Alarm must be tested after repair. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	avoided	N/A	one-time	N/A	N/A	N/A	N/A	$0	$0
49	Davis	9	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	avoided	6/20/2017	Annual	N/A	N/A	N/A	2017	$0	$0
50	Casmalia	1	The SPCC Plan did not comply with the regulatory requirements of 40 CFR 112.10 to address onshore oil drilling and workover facilities. In addition, the SPCC Plan has numerous corrective actions to be completed. Plan had a professional engineer evaluation of 2002 even though the plan was dated 2008.	delayed	4/7/2011	One-time	$5,000	12/31/2002	N/A	2011	$7,313	$7,860

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51	Casmalia	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	delayed	8/1/2010	One-time	$20,750	12/31/2002	N/A	2010	$28,641	$29,989
52	Casmalia	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 1 line in environmentally sensitive area (ESA).	Avoided	7/18/2011	Biennial	N/A	N/A	N/A	2011	$0	$0
53	Casmalia	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 35 other lines.	Avoided	7/18/2011	Every 5 years	N/A	N/A	N/A	2011	$0	$0
54	Casmalia	5	Secondary containment of the tank battery was compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	delayed	3/12/2008	capital	$1,200	12/31/2002	7	2008	$1,655	$1,800
55	Casmalia	6	Secondary containment of the wastewater pond was observed to be in a poor condition. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	delayed	3/12/2008	capital	$1,200	12/31/2002	7	2008	$1,655	$1,800
56	Casmalia	7	The Santa Barbara County Fire Department tested the alarm system at the tank battery which failed. Greka should perform regular tests on the alarm system to ensure its proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	avoided	6/20/2017	Annual	N/A	N/A	N/A	2017	$0	$0
57	Security	1	The 2004 and 2008 SPCC Plans did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - inadequately details the inspections, testing, and recordkeeping protocols (40 CFR 112.7e). - inadequately details oil production facility bulk storage containers (40 CFR 112.9(c), API 653, API 12R1, and STI SP001). - facility does not have a program of flow line maintenance (40 CFR 112.9(d), API 570, and ASME B31.3). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	delayed	1/28/2011	One-time	$5,000	12/31/2002	N/A	2011	$7,094	$7,767
58	Security	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9.(d), API 570, API 579-1, and ASME FFS-1)	delayed	8/1/2010	One-time	$23,000	12/31/2002	N/A	2010	$31,747	$33,240

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59	Security	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge (i.e., integrity of flow lines at the Waste Oil Tank and around the LCR tanks appeared compromised due to erosion and neglect at time of EPA inspection in 2008). (40 CFR 112.1b, 40 CFR 112.7(e), 40 CFR 112.9(d), and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flow line.)	Avoided	6/10/2009	Every 5 years	N/A	N/A	N/A	2009	$0	$0
60	Security	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires to provide appropriate containment and/or diversionary structures to prevent a discharge.)	delayed	6/20/2017	capital	$1,200	12/31/2002	7	2017	$1,660	$1,739
61	Security	5	Greka stored kerosene distillate (KD) to increase the viscosity of the heavy crude produced at the Security Lease. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. (40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contained spill oil.)	delayed	6/20/2017	capital	$10,000	12/31/2002	7	2017	$13,830	$14,488
62	Security	6	Multiple tanks are deteriorated and identified as out of service but still contain some product in them. (40 CFR 112.2, API 653, and API 12R1 require facilities to ensure containers are not used for storage unless the material used and conditions of storage are compatible.)	Delayed	3/12/2008	One-time	$1,500	12/31/2002	N/A	2008	$2,069	$2,249
63	Security	7	The secondary containment around the LCR tanks and Waste Oil Tank are compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. An inspection of the Pumper's Weekly Lease Inspection forms were reviewed and these items were not identified in any of the past inspections by the pumper dating back to 2005. (40 CFR 112.7c require appropriate containment and/or diversionary structures to prevent a discharge.)	Delayed	3/12/2008	capital	$1,200	12/31/2002	7	2008	$1,655	$1,800

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64	Security	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	Avoided	6/20/2017	Annual	N/A	N/A	N/A	2017	$0	$0
65	U-Cal	1	The SPCC Plan did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage control (40 CFR 112.7c and STI SP001). - inadequately details the inspections, testing, and recordkeeping protocols (40 CFR 112.7e). - inadequately details oil production facility bulk storage containers (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - facility does not have a program of flowline maintenance (40 CFR 112.9d, API 570, and ASME B31.3). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	avoided	N/A	One-time	N/A	N/A	N/A	N/A	$0	$0
66	U-Cal	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-a, and ASME FFS-1)	Avoided	N/A	One-time	N/A	N/A	N/A	N/A	$0	$0
67	U-Cal	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	avoided	1/1/2009	Every 5 years	N/A	N/A	N/A	2009	$0	$0
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	avoided	N/A	capital	N/A	N/A	7	N/A	$0	$0
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	avoided	N/A	capital	N/A	N/A	7	N/A	$0	$0
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	avoided	N/A	capital	N/A	N/A	7	N/A	$0	$0

Appendix B: Actual

A	B	C	D	E	F	G	H	I	J	K	L	M
Row	Lease	Item No.	Item Description	Avoided or delayed cost	Date of actual compliance expenditure	Type of cost (annual, capital, one-time)	Cost estimate (delayed costs only)	Date of cost estimate	Depreciable life, years (capital costs only)	Compliance year	Actual compliance cost estimate as of date of actual compliance	Actual compliance cost estimate as of end of actual compliance year
71	U-Cal	7	Per 40 CFR 112.9(c)(3), tanks should be covered under the inspection program per the SPCC plan or properly taken out of service. Several tanks were in deteriorating condition and secondary containment was failing. Either decommission the tanks or repair the tanks and test for integrity.	avoided	N/A	One-time	N/A	N/A	N/A	N/A	$0	$0
72	U-Cal	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	avoided	1/1/2009	Annual	N/A	N/A	N/A	2009	$0	$0
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	avoided	N/A	capital	N/A	N/A	7	N/A	$0	$0
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	avoided	N/A	capital	N/A	N/A	7	N/A	$0	$0
75	Escolle	1	Greka has not identified the location of all active and idle flow lines at the Escolle facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	delayed	8/1/2010	One-time	$7,500	12/31/2002	N/A	2010	$10,352	$10,839
76	Escolle	2	There is no regular program of flow line maintenance for each flow line at Lakeview to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	avoided	3/23/2010	Every 5 years	N/A	N/A	N/A	2010	$0	$0
77	Escolle	3	The 2007 SPCC Plan for the Escolle Lease did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - facility does not have a program for flow line maintenance (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - Plan does not address onshore drilling and workover facilities (40 CFR 112.10).	delayed	4/7/2011	One-time	$5,000	12/31/2002	N/A	2011	$7,313	$7,860
78	Escolle	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to property identify problems requiring correction at the facility.)	Avoided	6/20/2017	Annual	N/A	N/A	N/A	2017	$0	$0
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	delayed	3/12/2008	Capital	$1,200	12/31/2002	7	2008	$1,655	$1,800

Appendix B: Actual

A	B	C	D	E	F	G	H	I	J	K	L	M
Row	Lease	Item No.	Item Description	Avoided or delayed cost	Date of actual compliance expenditure	Type of cost (annual, capital, one-time)	Cost estimate (delayed costs only)	Date of cost estimate	Depreciable life, years (capital costs only)	Compliance year	Actual compliance cost estimate as of date of actual compliance	Actual compliance cost estimate as of end of actual compliance year
80	Battles	1	The 2004 and 2008 SPCC Plans did not comply with the regulatory requirements of 40 CFR 112. - inadequately details secondary containment and drainage controls (40 CFR 112.7c and STI SP001). - inadequately details the inspections, testing, and recordkeeping protocols (40 CFR 112.7e). - inadequately details oil production facility bulk storage containers (40 CFR 112.9c, API 653, API 12R1, and STI SP001). - facility does not have a program of flow line maintenance (40 CFR 112.9d, API 570, and ASME B21.3). - does not address onshore drilling and workover facilities (40 CFR 112.10).	delayed	5/5/2011	One-time	$5,000	12/31/2002	N/A	2011	$7,308	$7,796
81	Battles	2	Greka has not identified the location of all active and idle flow lines at the facility so as to include in a regular inspection program. (40 CFR 112.9d, API 570, API 579-1, and ASME FFS-1)	delayed	8/1/2010	One-time	$14,250	12/31/2002	N/A	2010	$19,669	$20,595
82	Battles	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 3 lines in environmentally sensitive areas (ESA).	avoided	2/22/2010	Biennial	N/A	N/A	N/A	2010	$0	$0
83	Battles	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 23 other lines.	avoided	2/22/2010	Every 5 years	N/A	N/A	N/A	2010	$0	$0
84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	delayed	6/20/2017	capital	$1,200	12/31/2002	7	2017	$1,660	$1,739
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	delayed	3/12/2008	capital	$1,200	12/31/2002	7	2008	$1,655	$1,800
86	Battles	7	Tank UO 903 should be identified as "out of service", have all piping disconnected, open the hatches, and remove all liquids. A new tank should be installed to replace the deteriorated tank. (40 CFR 112.2, API 653, and API 12R1 require facilities to ensure containers are not used for storage unless the material used and conditions of storage are compatible.)	delayed	1/1/2014	One-time	$1,500	12/31/2002	N/A	2014	$2,158	$2,359

Appendix B: Actual

A Row	B Lease	C Item No.	D Item Description	E Avoided or delayed cost	F Date of actual compliance expenditure	G Type of cost (annual, capital, one-time)	H Cost estimate (delayed costs only)	I Date of cost estimate	J Depreciable life, years (capital costs only)	K Compliance year	L Actual compliance cost estimate as of date of actual compliance	M Actual compliance cost estimate as of end of actual compliance year
87	Battles	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	Avoided	6/20/2017	Annual	N/A	N/A	N/A	2017	$0	$0

Notes by Column:

[A] - [K]	Reproduced from "Cost Inputs" table.
[L]	Cost estimates in [H] are adjusted for inflation to the actual compliance date [F] using the Plant Cost Index (PCI). Equal to [column H] * [PCI as of date in column F] / [PCI as of date in column I].
[M]	Using the year-specific WACC as the discount rate, [column L] is converted to net present value (NPV) as of the end of the actual compliance year. Equal to [column L] * (1 + WACC)^(portion of year between initial non-compliance date and Dec. 31 of that year). See "Other inputs" worksheet for year-specific WACC values.

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Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	I	J	K	L
								Cost estimate as of anniversary of initial non-compliance date:			
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	1998	1999	2000	2001
1	Williams B	1	-	-	-	One-time	-	$0	$0	$0	$0
2	Williams B	2	There is no regular program of flow line maintenance for each flow line at Williams B to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	6/30/2000	2/25/2010	Biennial	$98,744	$0	$0	$98,744	$0
3	Williams B	3	-	-	-	One-time	-	$0	$0	$0	$0
4	Williams B	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	6/30/2000	2/25/2010	Annual	$1,185	$0	$0	$1,185	$1,191
5	Williams B	5	-	-	-	Capital	-	$0	$0	$0	$0
6	Lloyd	1	-	-	-	One-time	-	$0	$0	$0	$0
7	Lloyd	2	-	-	-	One-time	-	$0	$0	$0	$0
8	Lloyd	3	-	-	-	One-time	-	$0	$0	$0	$0
9	Lloyd	4	-	-	-	Capital	-	$0	$0	$0	$0
10	Lakeview	1	-	-	-	One-time	-	$0	$0	$0	$0
11	Lakeview	2	-	-	-	One-time	-	$0	$0	$0	$0
12	Lakeview	3	-	-	-	Capital	-	$0	$0	$0	$0
13	Lakeview	4	-	-	-	One-time	-	$0	$0	$0	$0
14	Lakeview	5	-	-	-	Capital	-	$0	$0	$0	$0
15	Los Flores	1	-	-	-	One-time	-	$0	$0	$0	$0
16	Los Flores	2	-	-	-	One-time	-	$0	$0	$0	$0
17	Los Flores	3	There is no regular program of flow line maintenance for each flow line at Los Flores to reduce the likelihood of a discharge. (40 CFR 112.1b, 112,7e, and 112,9d and API 570)	8/31/2002	5/20/2010	Every 5 years	$32,565	$0	$0	$0	$0
18	Los Flores	4	-	-	-	One-time	-	$0	$0	$0	$0
19	Los Flores	5	-	-	-	capital	-	$0	$0	$0	$0
20	Los Flores	6	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$0	$0	$0	$0
21	Los Flores	7	-	-	-	capital	-	$0	$0	$0	$0
22	Bell	1	-	-	-	one-time	-	$0	$0	$0	$0
23	Bell	2	-	-	-	one-time	-	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	M	N	O	P
Row	**Lease**	**Item No.**	**Item Description**	**Date of initial non-compliance**	**Date recurring costs incurred ("avoided through")**	**Type of cost (capital, one-time, annual)**	**Cost estimate as of initial non-compliance date**	**2002**	**2003**	**2004**	**2005**
1	Williams B	1	-	-	-	One-time	-	$0	$0	$0	$0
2	Williams B	2	There is no regular program of flow line maintenance for each flow line at Williams B to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	6/30/2000	2/25/2010	Biennial	$98,744	$99,573	$0	$111,178	$0
3	Williams B	3	-	-	-	One-time	-	$0	$0	$0	$0
4	Williams B	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	6/30/2000	2/25/2010	Annual	$1,185	$1,195	$1,206	$1,334	$1,406
5	Williams B	5	-	-	-	Capital	-	$0	$0	$0	$0
6	Lloyd	1	-	-	-	One-time	-	$0	$0	$0	$0
7	Lloyd	2	-	-	-	One-time	-	$0	$0	$0	$0
8	Lloyd	3	-	-	-	One-time	-	$0	$0	$0	$0
9	Lloyd	4	-	-	-	Capital	-	$0	$0	$0	$0
10	Lakeview	1	-	-	-	One-time	-	$0	$0	$0	$0
11	Lakeview	2	-	-	-	One-time	-	$0	$0	$0	$0
12	Lakeview	3	-	-	-	Capital	-	$0	$0	$0	$0
13	Lakeview	4	-	-	-	One-time	-	$0	$0	$0	$0
14	Lakeview	5	-	-	-	Capital	-	$0	$0	$0	$0
15	Los Flores	1	-	-	-	One-time	-	$0	$0	$0	$0
16	Los Flores	2	-	-	-	One-time	-	$0	$0	$0	$0
17	Los Flores	3	There is no regular program of flow line maintenance for each flow line at Los Flores to reduce the likelihood of a discharge. (40 CFR 112.1b, 112,7e, and 112,9d and API 570)	8/31/2002	5/20/2010	Every 5 years	$32,565	$32,565	$0	$0	$0
18	Los Flores	4	-	-	-	One-time	-	$0	$0	$0	$0
19	Los Flores	5	-	-	-	capital	-	$0	$0	$0	$0
20	Los Flores	6	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,202	$1,213	$1,378	$1,391
21	Los Flores	7	-	-	-	capital	-	$0	$0	$0	$0
22	Bell	1	-	-	-	one-time	-	$0	$0	$0	$0
23	Bell	2	-	-	-	one-time	-	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	Q	R	S	T
Row	**Lease**	**Item No.**	**Item Description**	**Date of initial non-compliance**	**Date recurring costs incurred ("avoided through")**	**Type of cost (capital, one-time, annual)**	**Cost estimate as of initial non-compliance date**	**2006**	**2007**	**2008**	**2009**
1	Williams B	1	-	-	-	One-time	-	$0	$0	$0	$0
2	Williams B	2	There is no regular program of flow line maintenance for each flow line at Williams B to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	6/30/2000	2/25/2010	Biennial	$98,744	$126,250	$0	$149,987	$0
3	Williams B	3	-	-	-	One-time	-	$0	$0	$0	$0
4	Williams B	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	6/30/2000	2/25/2010	Annual	$1,185	$1,515	$1,606	$1,800	$1,543
5	Williams B	5	-	-	-	Capital	-	$0	$0	$0	$0
6	Lloyd	1	-	-	-	One-time	-	$0	$0	$0	$0
7	Lloyd	2	-	-	-	One-time	-	$0	$0	$0	$0
8	Lloyd	3	-	-	-	One-time	-	$0	$0	$0	$0
9	Lloyd	4	-	-	-	Capital	-	$0	$0	$0	$0
10	Lakeview	1	-	-	-	One-time	-	$0	$0	$0	$0
11	Lakeview	2	-	-	-	One-time	-	$0	$0	$0	$0
12	Lakeview	3	-	-	-	Capital	-	$0	$0	$0	$0
13	Lakeview	4	-	-	-	One-time	-	$0	$0	$0	$0
14	Lakeview	5	-	-	-	Capital	-	$0	$0	$0	$0
15	Los Flores	1	-	-	-	One-time	-	$0	$0	$0	$0
16	Los Flores	2	-	-	-	One-time	-	$0	$0	$0	$0
17	Los Flores	3	There is no regular program of flow line maintenance for each flow line at Los Flores to reduce the likelihood of a discharge. (40 CFR 112.1b, 112,7e, and 112,9d and API 570)	8/31/2002	5/20/2010	Every 5 years	$32,565	$0	$43,390	$0	$0
18	Los Flores	4	-	-	-	One-time	-	$0	$0	$0	$0
19	Los Flores	5	-	-	-	capital	-	$0	$0	$0	$0
20	Los Flores	6	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,537	$1,602	$1,867	$1,573
21	Los Flores	7	-	-	-	capital	-	$0	$0	$0	$0
22	Bell	1	-	-	-	one-time	-	$0	$0	$0	$0
23	Bell	2	-	-	-	one-time	-	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	U	V	W	X
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	2010	2011	2012	2013
1	Williams B	1	-	-	-	One-time	-	$0	$0	$0	$0
2	Williams B	2	There is no regular program of flow line maintenance for each flow line at Williams B to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	6/30/2000	2/25/2010	Biennial	$98,744	$0	$0	$0	$0
3	Williams B	3	-	-	-	One-time	-	$0	$0	$0	$0
4	Williams B	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	6/30/2000	2/25/2010	Annual	$1,185	$0	$0	$0	$0
5	Williams B	5	-	-	-	Capital	-	$0	$0	$0	$0
6	Lloyd	1	-	-	-	One-time	-	$0	$0	$0	$0
7	Lloyd	2	-	-	-	One-time	-	$0	$0	$0	$0
8	Lloyd	3	-	-	-	One-time	-	$0	$0	$0	$0
9	Lloyd	4	-	-	-	Capital	-	$0	$0	$0	$0
10	Lakeview	1	-	-	-	One-time	-	$0	$0	$0	$0
11	Lakeview	2	-	-	-	One-time	-	$0	$0	$0	$0
12	Lakeview	3	-	-	-	Capital	-	$0	$0	$0	$0
13	Lakeview	4	-	-	-	One-time	-	$0	$0	$0	$0
14	Lakeview	5	-	-	-	Capital	-	$0	$0	$0	$0
15	Los Flores	1	-	-	-	One-time	-	$0	$0	$0	$0
16	Los Flores	2	-	-	-	One-time	-	$0	$0	$0	$0
17	Los Flores	3	There is no regular program of flow line maintenance for each flow line at Los Flores to reduce the likelihood of a discharge. (40 CFR 112.1b, 112,7e, and 112,9d and API 570)	8/31/2002	5/20/2010	Every 5 years	$32,565	$0	$0	$0	$0
18	Los Flores	4	-	-	-	One-time	-	$0	$0	$0	$0
19	Los Flores	5	-	-	-	capital	-	$0	$0	$0	$0
20	Los Flores	6	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,656	$1,797	$1,738	$1,702
21	Los Flores	7	-	-	-	capital	-	$0	$0	$0	$0
22	Bell	1	-	-	-	one-time	-	$0	$0	$0	$0
23	Bell	2	-	-	-	one-time	-	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	Y	Z	AA	AB
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	2014	2015	2016	2017
1	Williams B	1	-	-	-	One-time	-	$0	$0	$0	$0
2	Williams B	2	There is no regular program of flow line maintenance for each flow line at Williams B to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	6/30/2000	2/25/2010	Biennial	$98,744	$0	$0	$0	$0
3	Williams B	3	-	-	-	One-time	-	$0	$0	$0	$0
4	Williams B	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	6/30/2000	2/25/2010	Annual	$1,185	$0	$0	$0	$0
5	Williams B	5	-	-	-	Capital	-	$0	$0	$0	$0
6	Lloyd	1	-	-	-	One-time	-	$0	$0	$0	$0
7	Lloyd	2	-	-	-	One-time	-	$0	$0	$0	$0
8	Lloyd	3	-	-	-	One-time	-	$0	$0	$0	$0
9	Lloyd	4	-	-	-	Capital	-	$0	$0	$0	$0
10	Lakeview	1	-	-	-	One-time	-	$0	$0	$0	$0
11	Lakeview	2	-	-	-	One-time	-	$0	$0	$0	$0
12	Lakeview	3	-	-	-	Capital	-	$0	$0	$0	$0
13	Lakeview	4	-	-	-	One-time	-	$0	$0	$0	$0
14	Lakeview	5	-	-	-	Capital	-	$0	$0	$0	$0
15	Los Flores	1	-	-	-	One-time	-	$0	$0	$0	$0
16	Los Flores	2	-	-	-	One-time	-	$0	$0	$0	$0
17	Los Flores	3	There is no regular program of flow line maintenance for each flow line at Los Flores to reduce the likelihood of a discharge. (40 CFR 112.1b, 112,7e, and 112,9d and API 570)	8/31/2002	5/20/2010	Every 5 years	$32,565	$0	$0	$0	$0
18	Los Flores	4	-	-	-	One-time	-	$0	$0	$0	$0
19	Los Flores	5	-	-	-	capital	-	$0	$0	$0	$0
20	Los Flores	6	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,744	$1,670	$1,634	$0
21	Los Flores	7	-	-	-	capital	-	$0	$0	$0	$0
22	Bell	1	-	-	-	one-time	-	$0	$0	$0	$0
23	Bell	2	-	-	-	one-time	-	$0	$0	$0	$0

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Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	I	J	K	L
								Cost estimate as of anniversary of initial non-compliance date:			
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	1998	1999	2000	2001
24	Bell	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.)	11/30/1999	1/11/2010	Every 5 years	$209,191	$0	$209,191	$0	$0
25	Bell	4a	-	-	-	one-time	-	$0	$0	$0	$0
26	Bell	4b	-	-	-	one-time	-	$0	$0	$0	$0
27	Bell	4c	-	-	-	one-time	-	$0	$0	$0	$0
28	Bell	4d	-	-	-	one-time	-	$0	$0	$0	$0
29	Bell	4f	-	-	-	one-time	-	$0	$0	$0	$0
30	Bell	4g	-	-	-	one-time	-	$0	$0	$0	$0
31	Bell	4h	-	-	-	one-time	-	$0	$0	$0	$0
32	Bell	5	-	-	-	capital	-	$0	$0	$0	$0
33	Bell	6	-	-	-	Capital	-	$0	$0	$0	$0
34	Bell	7	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$0	$1,181	$1,193	$1,183
35	Bell	8	-	-	-	capital	-	$0	$0	$0	$0
36	Chamberlin	1	-	-	-	one-time	-	$0	$0	$0	$0
37	Chamberlin	2	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	2/17/2011	Every 5 years	$17,535	$0	$0	$0	$0
38	Chamberlin	3	-	-	-	capital	-	$0	$0	$0	$0
39	Chamberlin	4	-	-	-	capital	-	$0	$0	$0	$0
40	Chamberlin	5	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$0	$0	$0	$0
41	Davis	1	-	-	-	one-time	-	$0	$0	$0	$0
42	Davis	2	-	-	-	one-time	-	$0	$0	$0	$0

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Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	M	N	O	P
Row	**Lease**	**Item No.**	**Item Description**	**Date of initial non-compliance**	**Date recurring costs incurred ("avoided through")**	**Type of cost (capital, one-time, annual)**	**Cost estimate as of initial non-compliance date**	**2002**	**2003**	**2004**	**2005**
24	Bell	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.)	11/30/1999	1/11/2010	Every 5 years	$209,191	$0	$0	$246,876	$0
25	Bell	4a	-	-	-	one-time	-	$0	$0	$0	$0
26	Bell	4b	-	-	-	one-time	-	$0	$0	$0	$0
27	Bell	4c	-	-	-	one-time	-	$0	$0	$0	$0
28	Bell	4d	-	-	-	one-time	-	$0	$0	$0	$0
29	Bell	4f	-	-	-	one-time	-	$0	$0	$0	$0
30	Bell	4g	-	-	-	one-time	-	$0	$0	$0	$0
31	Bell	4h	-	-	-	one-time	-	$0	$0	$0	$0
32	Bell	5	-	-	-	capital	-	$0	$0	$0	$0
33	Bell	6	-	-	-	Capital	-	$0	$0	$0	$0
34	Bell	7	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,202	$1,227	$1,394	$1,428
35	Bell	8	-	-	-	capital	-	$0	$0	$0	$0
36	Chamberlin	1	-	-	-	one-time	-	$0	$0	$0	$0
37	Chamberlin	2	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	2/17/2011	Every 5 years	$17,535	$17,535	$0	$0	$0
38	Chamberlin	3	-	-	-	capital	-	$0	$0	$0	$0
39	Chamberlin	4	-	-	-	capital	-	$0	$0	$0	$0
40	Chamberlin	5	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,202	$1,213	$1,378	$1,391
41	Davis	1	-	-	-	one-time	-	$0	$0	$0	$0
42	Davis	2	-	-	-	one-time	-	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	Q	R	S	T
Row	**Lease**	**Item No.**	**Item Description**	**Date of initial non-compliance**	**Date recurring costs incurred ("avoided through")**	**Type of cost (capital, one-time, annual)**	**Cost estimate as of initial non-compliance date**	**2006**	**2007**	**2008**	**2009**
24	Bell	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.)	11/30/1999	1/11/2010	Every 5 years	$209,191	$0	$0	$0	$279,704
25	Bell	4a	-	-	-	one-time	-	$0	$0	$0	$0
26	Bell	4b	-	-	-	one-time	-	$0	$0	$0	$0
27	Bell	4c	-	-	-	one-time	-	$0	$0	$0	$0
28	Bell	4d	-	-	-	one-time	-	$0	$0	$0	$0
29	Bell	4f	-	-	-	one-time	-	$0	$0	$0	$0
30	Bell	4g	-	-	-	one-time	-	$0	$0	$0	$0
31	Bell	4h	-	-	-	one-time	-	$0	$0	$0	$0
32	Bell	5	-	-	-	capital	-	$0	$0	$0	$0
33	Bell	6	-	-	-	Capital	-	$0	$0	$0	$0
34	Bell	7	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,542	$1,586	$1,707	$1,580
35	Bell	8	-	-	-	capital	-	$0	$0	$0	$0
36	Chamberlin	1	-	-	-	one-time	-	$0	$0	$0	$0
37	Chamberlin	2	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	2/17/2011	Every 5 years	$17,535	$0	$23,364	$0	$0
38	Chamberlin	3	-	-	-	capital	-	$0	$0	$0	$0
39	Chamberlin	4	-	-	-	capital	-	$0	$0	$0	$0
40	Chamberlin	5	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,537	$1,602	$1,867	$1,573
41	Davis	1	-	-	-	one-time	-	$0	$0	$0	$0
42	Davis	2	-	-	-	one-time	-	$0	$0	$0	$0

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Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	U	V	W	X
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	2010	2011	2012	2013
24	Bell	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.)	11/30/1999	1/11/2010	Every 5 years	$209,191	$0	$0	$0	$0
25	Bell	4a	-	-	-	one-time	-	$0	$0	$0	$0
26	Bell	4b	-	-	-	one-time	-	$0	$0	$0	$0
27	Bell	4c	-	-	-	one-time	-	$0	$0	$0	$0
28	Bell	4d	-	-	-	one-time	-	$0	$0	$0	$0
29	Bell	4f	-	-	-	one-time	-	$0	$0	$0	$0
30	Bell	4g	-	-	-	one-time	-	$0	$0	$0	$0
31	Bell	4h	-	-	-	one-time	-	$0	$0	$0	$0
32	Bell	5	-	-	-	capital	-	$0	$0	$0	$0
33	Bell	6	-	-	-	Capital	-	$0	$0	$0	$0
34	Bell	7	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,678	$1,781	$1,720	$1,708
35	Bell	8	-	-	-	capital	-	$0	$0	$0	$0
36	Chamberlin	1	-	-	-	one-time	-	$0	$0	$0	$0
37	Chamberlin	2	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	2/17/2011	Every 5 years	$17,535	$0	$0	$0	$0
38	Chamberlin	3	-	-	-	capital	-	$0	$0	$0	$0
39	Chamberlin	4	-	-	-	capital	-	$0	$0	$0	$0
40	Chamberlin	5	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,656	$1,797	$1,738	$1,702
41	Davis	1	-	-	-	one-time	-	$0	$0	$0	$0
42	Davis	2	-	-	-	one-time	-	$0	$0	$0	$0

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Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	Y	Z	AA	AB
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	2014	2015	2016	2017
24	Bell	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.)	11/30/1999	1/11/2010	Every 5 years	$209,191	$0	$0	$0	$0
25	Bell	4a	-	-	-	one-time	-	$0	$0	$0	$0
26	Bell	4b	-	-	-	one-time	-	$0	$0	$0	$0
27	Bell	4c	-	-	-	one-time	-	$0	$0	$0	$0
28	Bell	4d	-	-	-	one-time	-	$0	$0	$0	$0
29	Bell	4f	-	-	-	one-time	-	$0	$0	$0	$0
30	Bell	4g	-	-	-	one-time	-	$0	$0	$0	$0
31	Bell	4h	-	-	-	one-time	-	$0	$0	$0	$0
32	Bell	5	-	-	-	capital	-	$0	$0	$0	$0
33	Bell	6	-	-	-	Capital	-	$0	$0	$0	$0
34	Bell	7	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,743	$1,636	$1,640	$0
35	Bell	8	-	-	-	capital	-	$0	$0	$0	$0
36	Chamberlin	1	-	-	-	one-time	-	$0	$0	$0	$0
37	Chamberlin	2	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	2/17/2011	Every 5 years	$17,535	$0	$0	$0	$0
38	Chamberlin	3	-	-	-	capital	-	$0	$0	$0	$0
39	Chamberlin	4	-	-	-	capital	-	$0	$0	$0	$0
40	Chamberlin	5	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,744	$1,670	$1,634	$0
41	Davis	1	-	-	-	one-time	-	$0	$0	$0	$0
42	Davis	2	-	-	-	one-time	-	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	I	J	K	L	M
								Cost estimate as of anniversary of initial non-compliance date:				
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	1998	1999	2000	2001	2002
43	Davis	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 2 flow lines identified in Pipeline Management Plan.	8/31/2002	3/9/2011	Biennial	$5,010	$0	$0	$0	$0	$5,010
44	Davis	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 28 other lines.	8/31/2002	3/9/2011	Every 5 years	$70,141	$0	$0	$0	$0	$70,141
45	Davis	5	-	-	-	capital	-	$0	$0	$0	$0	$0
46	Davis	6	-	-	-	capital	-	$0	$0	$0	$0	$0
47	Davis	7	-	-	-	One-time	-	$0	$0	$0	$0	$0
48	Davis	8	-	-	-	one-time	-	$0	$0	$0	$0	$0
49	Davis	9	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$0	$0	$0	$0	$1,202
50	Casmalia	1	-	-	-	One-time	-	$0	$0	$0	$0	$0
51	Casmalia	2	-	-	-	One-time	-	$0	$0	$0	$0	$0
52	Casmalia	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 1 line in environmentally sensitive area (ESA).	11/30/1999	7/18/2011	Biennial	$2,461	$0	$2,461	$0	$2,464	$0
53	Casmalia	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 35 other lines.	11/30/1999	7/18/2011	Every 5 years	$86,137	$0	$86,137	$0	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	N	O	P	Q	R
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	2003	2004	2005	2006	2007
43	Davis	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 2 flow lines identified in Pipeline Management Plan.	8/31/2002	3/9/2011	Biennial	$5,010	$0	$5,742	$0	$6,405	$0
44	Davis	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 28 other lines.	8/31/2002	3/9/2011	Every 5 years	$70,141	$0	$0	$0	$0	$93,456
45	Davis	5	-	-	-	capital	-	$0	$0	$0	$0	$0
46	Davis	6	-	-	-	capital	-	$0	$0	$0	$0	$0
47	Davis	7	-	-	-	One-time	-	$0	$0	$0	$0	$0
48	Davis	8	-	-	-	one-time	-	$0	$0	$0	$0	$0
49	Davis	9	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,213	$1,378	$1,391	$1,537	$1,602
50	Casmalia	1	-	-	-	One-time	-	$0	$0	$0	$0	$0
51	Casmalia	2	-	-	-	One-time	-	$0	$0	$0	$0	$0
52	Casmalia	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 1 line in environmentally sensitive area (ESA).	11/30/1999	7/18/2011	Biennial	$2,461	$2,557	$0	$2,976	$0	$3,303
53	Casmalia	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 35 other lines.	11/30/1999	7/18/2011	Every 5 years	$86,137	$0	$101,655	$0	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	S	T	U	V	W	X
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	2008	2009	2010	2011	2012	2013
43	Davis	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112 9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 2 flow lines identified in Pipeline Management Plan.	8/31/2002	3/9/2011	Biennial	$5,010	$7,778	$0	$6,902	$0	$0	$0
44	Davis	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112 9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 28 other lines.	8/31/2002	3/9/2011	Every 5 years	$70,141	$0	$0	$0	$0	$0	$0
45	Davis	5	-	-	-	capital	-	$0	$0	$0	$0	$0	$0
46	Davis	6	-	-	-	capital	-	$0	$0	$0	$0	$0	$0
47	Davis	7	-	-	-	One-time	-	$0	$0	$0	$0	$0	$0
48	Davis	8	-	-	-	one-time	-	$0	$0	$0	$0	$0	$0
49	Davis	9	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,867	$1,573	$1,656	$1,797	$1,738	$1,702
50	Casmalia	1	-	-	-	One-time	-	$0	$0	$0	$0	$0	$0
51	Casmalia	2	-	-	-	One-time	-	$0	$0	$0	$0	$0	$0
52	Casmalia	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 1 line in environmentally sensitive area (ESA).	11/30/1999	7/18/2011	Biennial	$2,461	$0	$3,291	$0	$0	$0	$0
53	Casmalia	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 35 other lines.	11/30/1999	7/18/2011	Every 5 years	$86,137	$0	$115,172	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	Y	Z	AA	AB
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	2014	2015	2016	2017
43	Davis	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 2 flow lines identified in Pipeline Management Plan.	8/31/2002	3/9/2011	Biennial	$5,010	$0	$0	$0	$0
44	Davis	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 28 other lines.	8/31/2002	3/9/2011	Every 5 years	$70,141	$0	$0	$0	$0
45	Davis	5	-	-	-	capital	-	$0	$0	$0	$0
46	Davis	6	-	-	-	capital	-	$0	$0	$0	$0
47	Davis	7	-	-	-	One-time	-	$0	$0	$0	$0
48	Davis	8	-	-	-	one-time	-	$0	$0	$0	$0
49	Davis	9	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,744	$1,670	$1,634	$0
50	Casmalia	1	-	-	-	One-time	-	$0	$0	$0	$0
51	Casmalia	2	-	-	-	One-time	-	$0	$0	$0	$0
52	Casmalia	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 1 line in environmentally sensitive area (ESA).	11/30/1999	7/18/2011	Biennial	$2,461	$0	$0	$0	$0
53	Casmalia	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 35 other lines.	11/30/1999	7/18/2011	Every 5 years	$86,137	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	I	J	K	L
								Cost estimate as of anniversary of initial non-compliance date:			
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	1998	1999	2000	2001
54	Casmalia	5	-	-	-	capital	-	$0	$0	$0	$0
55	Casmalia	6	-	-	-	capital	-	$0	$0	$0	$0
56	Casmalia	7	The Santa Barbara County Fire Department tested the alarm system at the tank battery which failed. Greka should perform regular tests on the alarm system to ensure its proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	2/12/2008	6/20/2017	Annual	$1,627	$0	$0	$0	$0
57	Security	1	-	-	-	One-time	-	$0	$0	$0	$0
58	Security	2	-	-	-	One-time	-	$0	$0	$0	$0
59	Security	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge (i.e., integrity of flow lines at the Waste Oil Tank and around the LCR tanks appeared compromised due to erosion and neglect at time of EPA inspection in 2008). (40 CFR 112.1b, 40 CFR 112.7(e), 40 CFR 112.9(d), and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flow line.)	8/31/2002	6/10/2009	Every 5 years	$82,666	$0	$0	$0	$0
60	Security	4	-	-	-	capital	-	$0	$0	$0	$0
61	Security	5	-	-	-	capital	-	$0	$0	$0	$0
62	Security	6	-	-	-	One-time	-	$0	$0	$0	$0
63	Security	7	-	-	-	capital	-	$0	$0	$0	$0
64	Security	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$0	$0	$0	$0
65	U-Cal	1	-	-	-	One-time	-	$0	$0	$0	$0
66	U-Cal	2	-	-	-	One-time	-	$0	$0	$0	$0
67	U-Cal	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	1/1/2009	Every 5 years	$102,706	$0	$0	$0	$0

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Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	M	N	O	P
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	2002	2003	2004	2005
54	Casmalia	5	-	-	-	capital	-	$0	$0	$0	$0
55	Casmalia	6	-	-	-	capital	-	$0	$0	$0	$0
56	Casmalia	7	The Santa Barbara County Fire Department tested the alarm system at the tank battery which failed. Greka should perform regular tests on the alarm system to ensure its proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	2/12/2008	6/20/2017	Annual	$1,627	$0	$0	$0	$0
57	Security	1	-	-	-	One-time	-	$0	$0	$0	$0
58	Security	2	-	-	-	One-time	-	$0	$0	$0	$0
59	Security	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge (i.e., integrity of flow lines at the Waste Oil Tank and around the LCR tanks appeared compromised due to erosion and neglect at time of EPA inspection in 2008). (40 CFR 112.1b, 40 CFR 112.7(e), 40 CFR 112.9(d), and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flow line.)	8/31/2002	6/10/2009	Every 5 years	$82,666	$82,666	$0	$0	$0
60	Security	4	-	-	-	capital	-	$0	$0	$0	$0
61	Security	5	-	-	-	capital	-	$0	$0	$0	$0
62	Security	6	-	-	-	One-time	-	$0	$0	$0	$0
63	Security	7	-	-	-	capital	-	$0	$0	$0	$0
64	Security	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,202	$1,213	$1,378	$1,391
65	U-Cal	1	-	-	-	One-time	-	$0	$0	$0	$0
66	U-Cal	2	-	-	-	One-time	-	$0	$0	$0	$0
67	U-Cal	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	1/1/2009	Every 5 years	$102,706	$102,706	$0	$0	$0

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Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	Q	R	S	T
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	2006	2007	2008	2009
54	Casmalia	5	-	-	-	capital	-	$0	$0	$0	$0
55	Casmalia	6	-	-	-	capital	-	$0	$0	$0	$0
56	Casmalia	7	The Santa Barbara County Fire Department tested the alarm system at the tank battery which failed. Greka should perform regular tests on the alarm system to ensure its proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	2/12/2008	6/20/2017	Annual	$1,627	$0	$0	$1,627	$1,605
57	Security	1	-	-	-	One-time	-	$0	$0	$0	$0
58	Security	2	-	-	-	One-time	-	$0	$0	$0	$0
59	Security	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge (i.e., integrity of flow lines at the Waste Oil Tank and around the LCR tanks appeared compromised due to erosion and neglect at time of EPA inspection in 2008). (40 CFR 112.1b, 40 CFR 112.7(e), 40 CFR 112.9(d), and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flow line.)	8/31/2002	6/10/2009	Every 5 years	$82,666	$0	$110,145	$0	$0
60	Security	4	-	-	-	capital	-	$0	$0	$0	$0
61	Security	5	-	-	-	capital	-	$0	$0	$0	$0
62	Security	6	-	-	-	One-time	-	$0	$0	$0	$0
63	Security	7	-	-	-	capital	-	$0	$0	$0	$0
64	Security	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,537	$1,602	$1,867	$1,573
65	U-Cal	1	-	-	-	One-time	-	$0	$0	$0	$0
66	U-Cal	2	-	-	-	One-time	-	$0	$0	$0	$0
67	U-Cal	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	1/1/2009	Every 5 years	$102,706	$0	$136,847	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	U	V	W	X
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	2010	2011	2012	2013
54	Casmalia	5	-	-	-	capital	-	$0	$0	$0	$0
55	Casmalia	6	-	-	-	capital	-	$0	$0	$0	$0
56	Casmalia	7	The Santa Barbara County Fire Department tested the alarm system at the tank battery which failed. Greka should perform regular tests on the alarm system to ensure its proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	2/12/2008	6/20/2017	Annual	$1,627	$1,625	$1,732	$1,797	$1,718
57	Security	1	-	-	-	One-time	-	$0	$0	$0	$0
58	Security	2	-	-	-	One-time	-	$0	$0	$0	$0
59	Security	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge (i.e., integrity of flow lines at the Waste Oil Tank and around the LCR tanks appeared compromised due to erosion and neglect at time of EPA inspection in 2008). (40 CFR 112.1b, 40 CFR 112.7(e), 40 CFR 112.9(d), and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flow line.)	8/31/2002	6/10/2009	Every 5 years	$82,666	$0	$0	$0	$0
60	Security	4	-	-	-	capital	-	$0	$0	$0	$0
61	Security	5	-	-	-	capital	-	$0	$0	$0	$0
62	Security	6	-	-	-	One-time	-	$0	$0	$0	$0
63	Security	7	-	-	-	capital	-	$0	$0	$0	$0
64	Security	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,656	$1,797	$1,738	$1,702
65	U-Cal	1	-	-	-	One-time	-	$0	$0	$0	$0
66	U-Cal	2	-	-	-	One-time	-	$0	$0	$0	$0
67	U-Cal	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	1/1/2009	Every 5 years	$102,706	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	Y	Z	AA	AB
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	2014	2015	2016	2017
54	Casmalia	5	-	-	-	capital	-	$0	$0	$0	$0
55	Casmalia	6	-	-	-	capital	-	$0	$0	$0	$0
56	Casmalia	7	The Santa Barbara County Fire Department tested the alarm system at the tank battery which failed. Greka should perform regular tests on the alarm system to ensure its proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	2/12/2008	6/20/2017	Annual	$1,627	$1,733	$1,720	$1,623	$1,648
57	Security	1	-	-	-	One-time	-	$0	$0	$0	$0
58	Security	2	-	-	-	One-time	-	$0	$0	$0	$0
59	Security	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge (i.e., integrity of flow lines at the Waste Oil Tank and around the LCR tanks appeared compromised due to erosion and neglect at time of EPA inspection in 2008). (40 CFR 112.1b, 40 CFR 112.7(e), 40 CFR 112.9(d), and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flow line.)	8/31/2002	6/10/2009	Every 5 years	$82,666	$0	$0	$0	$0
60	Security	4	-	-	-	capital	-	$0	$0	$0	$0
61	Security	5	-	-	-	capital	-	$0	$0	$0	$0
62	Security	6	-	-	-	One-time	-	$0	$0	$0	$0
63	Security	7	-	-	-	capital	-	$0	$0	$0	$0
64	Security	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,744	$1,670	$1,634	$0
65	U-Cal	1	-	-	-	One-time	-	$0	$0	$0	$0
66	U-Cal	2	-	-	-	One-time	-	$0	$0	$0	$0
67	U-Cal	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	1/1/2009	Every 5 years	$102,706	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	I	J	K	L
								Cost estimate as of anniversary of initial non-compliance date:			
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	1998	1999	2000	2001
68	U-Cal	4	-	-	-	capital	-	$0	$0	$0	$0
69	U-Cal	5	-	-	-	capital	-	$0	$0	$0	$0
70	U-Cal	6	-	-	-	capital	-	$0	$0	$0	$0
71	U-Cal	7	-	-	-	One-time	-	$0	$0	$0	$0
72	U-Cal	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	1/1/2009	Annual	$1,202	$0	$0	$0	$0
73	U-Cal	9	-	-	-	capital	-	$0	$0	$0	$0
74	U-Cal	10	-	-	-	capital	-	$0	$0	$0	$0
75	Escolle	1	-	-	-	One-time	-	$0	$0	$0	$0
76	Escolle	2	There is no regular program of flow line maintenance for each flow line at Lakeview to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	11/30/1999	3/23/2010	Every 5 years	$27,072	$0	$27,072	$0	$0
77	Escolle	3	-	-	-	One-time	-	$0	$0	$0	$0
78	Escolle	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to property identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$0	$1,181	$1,193	$1,183
79	Escolle	5	-	-	-	Capital	-	$0	$0	$0	$0
80	Battles	1	-	-	-	One-time	-	$0	$0	$0	$0
81	Battles	2	-	-	-	One-time	-	$0	$0	$0	$0
82	Battles	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 3 lines in environmentally sensitive areas (ESA).	11/30/1999	2/22/2010	Biennial	$7,383	$0	$7,383	$0	$7,391
83	Battles	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 23 other lines.	11/30/1999	2/22/2010	Every 5 years	$56,604	$0	$56,604	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	M	N	O	P
Row	**Lease**	**Item No.**	**Item Description**	**Date of initial non-compliance**	**Date recurring costs incurred ("avoided through")**	**Type of cost (capital, one-time, annual)**	**Cost estimate as of initial non-compliance date**	**2002**	**2003**	**2004**	**2005**
68	U-Cal	4	-	-	-	capital	-	$0	$0	$0	$0
69	U-Cal	5	-	-	-	capital	-	$0	$0	$0	$0
70	U-Cal	6	-	-	-	capital	-	$0	$0	$0	$0
71	U-Cal	7	-	-	-	One-time	-	$0	$0	$0	$0
72	U-Cal	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	1/1/2009	Annual	$1,202	$1,202	$1,213	$1,378	$1,391
73	U-Cal	9	-	-	-	capital	-	$0	$0	$0	$0
74	U-Cal	10	-	-	-	capital	-	$0	$0	$0	$0
75	Escolle	1	-	-	-	One-time	-	$0	$0	$0	$0
76	Escolle	2	There is no regular program of flow line maintenance for each flow line at Lakeview to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	11/30/1999	3/23/2010	Every 5 years	$27,072	$0	$0	$31,949	$0
77	Escolle	3	-	-	-	One-time	-	$0	$0	$0	$0
78	Escolle	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to property identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,202	$1,227	$1,394	$1,428
79	Escolle	5	-	-	-	Capital	-	$0	$0	$0	$0
80	Battles	1	-	-	-	One-time	-	$0	$0	$0	$0
81	Battles	2	-	-	-	One-time	-	$0	$0	$0	$0
82	Battles	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112 9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 3 lines in environmentally sensitive areas (ESA).	11/30/1999	2/22/2010	Biennial	$7,383	$0	$7,671	$0	$8,928
83	Battles	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112 9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 23 other lines.	11/30/1999	2/22/2010	Every 5 years	$56,604	$0	$0	$66,802	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	Q	R	S	T
Row	**Lease**	**Item No.**	**Item Description**	**Date of initial non-compliance**	**Date recurring costs incurred ("avoided through")**	**Type of cost (capital, one-time, annual)**	**Cost estimate as of initial non-compliance date**	**2006**	**2007**	**2008**	**2009**
68	U-Cal	4	-	-	-	capital	-	$0	$0	$0	$0
69	U-Cal	5	-	-	-	capital	-	$0	$0	$0	$0
70	U-Cal	6	-	-	-	capital	-	$0	$0	$0	$0
71	U-Cal	7	-	-	-	One-time	-	$0	$0	$0	$0
72	U-Cal	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	1/1/2009	Annual	$1,202	$1,537	$1,602	$1,867	$0
73	U-Cal	9	-	-	-	capital	-	$0	$0	$0	$0
74	U-Cal	10	-	-	-	capital	-	$0	$0	$0	$0
75	Escolle	1	-	-	-	One-time	-	$0	$0	$0	$0
76	Escolle	2	There is no regular program of flow line maintenance for each flow line at Lakeview to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	11/30/1999	3/23/2010	Every 5 years	$27,072	$0	$0	$0	$36,197
77	Escolle	3	-	-	-	One-time	-	$0	$0	$0	$0
78	Escolle	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to property identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,542	$1,586	$1,707	$1,580
79	Escolle	5	-	-	-	Capital	-	$0	$0	$0	$0
80	Battles	1	-	-	-	One-time	-	$0	$0	$0	$0
81	Battles	2	-	-	-	One-time	-	$0	$0	$0	$0
82	Battles	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 3 lines in environmentally sensitive areas (ESA).	11/30/1999	2/22/2010	Biennial	$7,383	$0	$9,910	$0	$9,872
83	Battles	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 23 other lines.	11/30/1999	2/22/2010	Every 5 years	$56,604	$0	$0	$0	$75,685

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	U	V	W	X
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	2010	2011	2012	2013
68	U-Cal	4	-	-	-	capital	-	$0	$0	$0	$0
69	U-Cal	5	-	-	-	capital	-	$0	$0	$0	$0
70	U-Cal	6	-	-	-	capital	-	$0	$0	$0	$0
71	U-Cal	7	-	-	-	One-time	-	$0	$0	$0	$0
72	U-Cal	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	1/1/2009	Annual	$1,202	$0	$0	$0	$0
73	U-Cal	9	-	-	-	capital	-	$0	$0	$0	$0
74	U-Cal	10	-	-	-	capital	-	$0	$0	$0	$0
75	Escolle	1	-	-	-	One-time	-	$0	$0	$0	$0
76	Escolle	2	There is no regular program of flow line maintenance for each flow line at Lakeview to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	11/30/1999	3/23/2010	Every 5 years	$27,072	$0	$0	$0	$0
77	Escolle	3	-	-	-	One-time	-	$0	$0	$0	$0
78	Escolle	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to property identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,678	$1,781	$1,720	$1,708
79	Escolle	5	-	-	-	Capital	-	$0	$0	$0	$0
80	Battles	1	-	-	-	One-time	-	$0	$0	$0	$0
81	Battles	2	-	-	-	One-time	-	$0	$0	$0	$0
82	Battles	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 3 lines in environmentally sensitive areas (ESA).	11/30/1999	2/22/2010	Biennial	$7,383	$0	$0	$0	$0
83	Battles	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 23 other lines.	11/30/1999	2/22/2010	Every 5 years	$56,604	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	Y	Z	AA	AB
Row	**Lease**	**Item No.**	**Item Description**	**Date of initial non-compliance**	**Date recurring costs incurred ("avoided through")**	**Type of cost (capital, one-time, annual)**	**Cost estimate as of initial non-compliance date**	**2014**	**2015**	**2016**	**2017**
68	U-Cal	4	-	-	-	capital	-	$0	$0	$0	$0
69	U-Cal	5	-	-	-	capital	-	$0	$0	$0	$0
70	U-Cal	6	-	-	-	capital	-	$0	$0	$0	$0
71	U-Cal	7	-	-	-	One-time	-	$0	$0	$0	$0
72	U-Cal	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	1/1/2009	Annual	$1,202	$0	$0	$0	$0
73	U-Cal	9	-	-	-	capital	-	$0	$0	$0	$0
74	U-Cal	10	-	-	-	capital	-	$0	$0	$0	$0
75	Escolle	1	-	-	-	One-time	-	$0	$0	$0	$0
76	Escolle	2	There is no regular program of flow line maintenance for each flow line at Lakeview to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	11/30/1999	3/23/2010	Every 5 years	$27,072	$0	$0	$0	$0
77	Escolle	3	-	-	-	One-time	-	$0	$0	$0	$0
78	Escolle	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to property identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,743	$1,636	$1,640	$0
79	Escolle	5	-	-	-	Capital	-	$0	$0	$0	$0
80	Battles	1	-	-	-	One-time	-	$0	$0	$0	$0
81	Battles	2	-	-	-	One-time	-	$0	$0	$0	$0
82	Battles	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 3 lines in environmentally sensitive areas (ESA).	11/30/1999	2/22/2010	Biennial	$7,383	$0	$0	$0	$0
83	Battles	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 23 other lines.	11/30/1999	2/22/2010	Every 5 years	$56,604	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	I	J	K	L
								Cost estimate as of anniversary of initial non-compliance date:			
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	1998	1999	2000	2001
84	Battles	5	-	-	-	capital	-	$0	$0	$0	$0
85	Battles	6	-	-	-	capital	-	$0	$0	$0	$0
86	Battles	7	-	-	-	One-time	-	$0	$0	$0	$0
87	Battles	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$0	$1,181	$1,193	$1,183
							SUM	$0	$392,392	$103,507	$14,593

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	M	N	O	P
Row	**Lease**	**Item No.**	**Item Description**	**Date of initial non-compliance**	**Date recurring costs incurred ("avoided through")**	**Type of cost (capital, one-time, annual)**	**Cost estimate as of initial non-compliance date**	**2002**	**2003**	**2004**	**2005**
84	Battles	5	-	-	-	capital	-	$0	$0	$0	$0
85	Battles	6	-	-	-	capital	-	$0	$0	$0	$0
86	Battles	7	-	-	-	One-time	-	$0	$0	$0	$0
87	Battles	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,202	$1,227	$1,394	$1,428
							SUM	**$421,008**	**$21,181**	**$576,608**	**$24,552**

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Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	Q	R	S	T
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	2006	2007	2008	2009
84	Battles	5	-	-	-	capital	-	$0	$0	$0	$0
85	Battles	6	-	-	-	capital	-	$0	$0	$0	$0
86	Battles	7	-	-	-	One-time	-	$0	$0	$0	$0
87	Battles	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,542	$1,586	$1,707	$1,580
							SUM	$146,481	$434,789	$175,647	$534,099

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	U	V	W	X
Row	**Lease**	**Item No.**	**Item Description**	**Date of initial non-compliance**	**Date recurring costs incurred ("avoided through")**	**Type of cost (capital, one-time, annual)**	**Cost estimate as of initial non-compliance date**	**2010**	**2011**	**2012**	**2013**
84	Battles	5	-	-	-	capital	-	$0	$0	$0	$0
85	Battles	6	-	-	-	capital	-	$0	$0	$0	$0
86	Battles	7	-	-	-	One-time	-	$0	$0	$0	$0
87	Battles	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,678	$1,781	$1,720	$1,708
							SUM	**$20,186**	**$14,262**	**$13,910**	**$13,652**

Appendix B: Avoided Recurring Costs – Nominal

A	B	C	D	E	F	G	H	Y	Z	AA	AB
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	2014	2015	2016	2017
84	Battles	5	-	-	-	capital	-	$0	$0	$0	$0
85	Battles	6	-	-	-	capital	-	$0	$0	$0	$0
86	Battles	7	-	-	-	One-time	-	$0	$0	$0	$0
87	Battles	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,743	$1,636	$1,640	$0
							SUM	**$13,941**	**$13,307**	**$13,078**	**$1,648**

	Notes by column:
[A] - [H]	Reproduced from "Cost inputs" table for recurring costs only.
[I] - [AB]	For applicable years specified by the period from [E] to [F], recurring costs are reported as the cost estimate in [H] adjusted for inflation using the Plant Cost Index (PCI), as of the applicable anniversary of the non-compliance date. Equal to [column H] * [PCI as of dates in columns I-AB] / [PCI as of date in column E].
[AB]	Period costs for 2017 are reported if and only if the applicable anniversary of the initial non-compliance is prior to the trial date.

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	I	J	K	L
								Present value of cost estimate as of Dec. 31 of initial non-comp			
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/1998	12/31/1999	12/31/2000	12/31/2001
1	Williams B	1	-	-	-	One-time	-	$0	$0	$0	$0
2	Williams B	2	There is no regular program of flow line maintenance for each flow line at Williams B to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	6/30/2000	2/25/2010	Biennial	$98,744	$0	$0	$104,355	$0
3	Williams B	3	-	-	-	One-time	-	$0	$0	$0	$0
4	Williams B	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	6/30/2000	2/25/2010	Annual	$1,185	$0	$0	$1,252	$1,253
5	Williams B	5	-	-	-	Capital	-	$0	$0	$0	$0
6	Lloyd	1	-	-	-	One-time	-	$0	$0	$0	$0
7	Lloyd	2	-	-	-	One-time	-	$0	$0	$0	$0
8	Lloyd	3	-	-	-	One-time	-	$0	$0	$0	$0
9	Lloyd	4	-	-	-	Capital	-	$0	$0	$0	$0
10	Lakeview	1	-	-	-	One-time	-	$0	$0	$0	$0
11	Lakeview	2	-	-	-	One-time	-	$0	$0	$0	$0
12	Lakeview	3	-	-	-	Capital	-	$0	$0	$0	$0
13	Lakeview	4	-	-	-	One-time	-	$0	$0	$0	$0
14	Lakeview	5	-	-	-	Capital	-	$0	$0	$0	$0
15	Los Flores	1	-	-	-	One-time	-	$0	$0	$0	$0
16	Los Flores	2	-	-	-	One-time	-	$0	$0	$0	$0
17	Los Flores	3	There is no regular program of flow line maintenance for each flow line at Los Flores to reduce the likelihood of a discharge. (40 CFR 112.1b, 112,7e, and 112,9d and API 570)	8/31/2002	5/20/2010	Every 5 years	$32,565	$0	$0	$0	$0
18	Los Flores	4	-	-	-	One-time	-	$0	$0	$0	$0
19	Los Flores	5	-	-	-	capital	-	$0	$0	$0	$0
20	Los Flores	6	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$0	$0	$0	$0
21	Los Flores	7	-	-	-	capital	-	$0	$0	$0	$0
22	Bell	1	-	-	-	one-time	-	$0	$0	$0	$0
23	Bell	2	-	-	-	one-time	-	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	M	N	O	P
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2002	12/31/2003	12/31/2004	12/31/2005
1	Williams B	1	-	-	-	One-time	-	$0	$0	$0	$0
2	Williams B	2	There is no regular program of flow line maintenance for each flow line at Williams B to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	6/30/2000	2/25/2010	Biennial	$98,744	$105,090	$0	$116,149	$0
3	Williams B	3	-	-	-	One-time	-	$0	$0	$0	$0
4	Williams B	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	6/30/2000	2/25/2010	Annual	$1,185	$1,261	$1,264	$1,394	$1,468
5	Williams B	5	-	-	-	Capital	-	$0	$0	$0	$0
6	Lloyd	1	-	-	-	One-time	-	$0	$0	$0	$0
7	Lloyd	2	-	-	-	One-time	-	$0	$0	$0	$0
8	Lloyd	3	-	-	-	One-time	-	$0	$0	$0	$0
9	Lloyd	4	-	-	-	Capital	-	$0	$0	$0	$0
10	Lakeview	1	-	-	-	One-time	-	$0	$0	$0	$0
11	Lakeview	2	-	-	-	One-time	-	$0	$0	$0	$0
12	Lakeview	3	-	-	-	Capital	-	$0	$0	$0	$0
13	Lakeview	4	-	-	-	One-time	-	$0	$0	$0	$0
14	Lakeview	5	-	-	-	Capital	-	$0	$0	$0	$0
15	Los Flores	1	-	-	-	One-time	-	$0	$0	$0	$0
16	Los Flores	2	-	-	-	One-time	-	$0	$0	$0	$0
17	Los Flores	3	There is no regular program of flow line maintenance for each flow line at Los Flores to reduce the likelihood of a discharge. (40 CFR 112.1b, 112,7e, and 112,9d and API 570)	8/31/2002	5/20/2010	Every 5 years	$32,565	$33,751	$0	$0	$0
18	Los Flores	4	-	-	-	One-time	-	$0	$0	$0	$0
19	Los Flores	5	-	-	-	capital	-	$0	$0	$0	$0
20	Los Flores	6	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,246	$1,252	$1,419	$1,432
21	Los Flores	7	-	-	-	capital	-	$0	$0	$0	$0
22	Bell	1	-	-	-	one-time	-	$0	$0	$0	$0
23	Bell	2	-	-	-	one-time	-	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	Q	R	S	T
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2006	12/31/2007	12/31/2008	12/31/2009
1	Williams B	1	-	-	-	One-time	-	$0	$0	$0	$0
2	Williams B	2	There is no regular program of flow line maintenance for each flow line at Williams B to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	6/30/2000	2/25/2010	Biennial	$98,744	$132,445	$0	$158,031	$0
3	Williams B	3	-	-	-	One-time	-	$0	$0	$0	$0
4	Williams B	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	6/30/2000	2/25/2010	Annual	$1,185	$1,589	$1,677	$1,896	$1,642
5	Williams B	5	-	-	-	Capital	-	$0	$0	$0	$0
6	Lloyd	1	-	-	-	One-time	-	$0	$0	$0	$0
7	Lloyd	2	-	-	-	One-time	-	$0	$0	$0	$0
8	Lloyd	3	-	-	-	One-time	-	$0	$0	$0	$0
9	Lloyd	4	-	-	-	Capital	-	$0	$0	$0	$0
10	Lakeview	1	-	-	-	One-time	-	$0	$0	$0	$0
11	Lakeview	2	-	-	-	One-time	-	$0	$0	$0	$0
12	Lakeview	3	-	-	-	Capital	-	$0	$0	$0	$0
13	Lakeview	4	-	-	-	One-time	-	$0	$0	$0	$0
14	Lakeview	5	-	-	-	Capital	-	$0	$0	$0	$0
15	Los Flores	1	-	-	-	One-time	-	$0	$0	$0	$0
16	Los Flores	2	-	-	-	One-time	-	$0	$0	$0	$0
17	Los Flores	3	There is no regular program of flow line maintenance for each flow line at Los Flores to reduce the likelihood of a discharge. (40 CFR 112.1b, 112,7e, and 112,9d and API 570)	8/31/2002	5/20/2010	Every 5 years	$32,565	$0	$44,657	$0	$0
18	Los Flores	4	-	-	-	One-time	-	$0	$0	$0	$0
19	Los Flores	5	-	-	-	capital	-	$0	$0	$0	$0
20	Los Flores	6	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,587	$1,649	$1,933	$1,639
21	Los Flores	7	-	-	-	capital	-	$0	$0	$0	$0
22	Bell	1	-	-	-	one-time	-	$0	$0	$0	$0
23	Bell	2	-	-	-	one-time	-	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	U	V	W	X
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2010	12/31/2011	12/31/2012	12/31/2013
1	Williams B	1	-	-	-	One-time	-	$0	$0	$0	$0
2	Williams B	2	There is no regular program of flow line maintenance for each flow line at Williams B to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	6/30/2000	2/25/2010	Biennial	$98,744	$0	$0	$0	$0
3	Williams B	3	-	-	-	One-time	-	$0	$0	$0	$0
4	Williams B	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	6/30/2000	2/25/2010	Annual	$1,185	$0	$0	$0	$0
5	Williams B	5	-	-	-	Capital	-	$0	$0	$0	$0
6	Lloyd	1	-	-	-	One-time	-	$0	$0	$0	$0
7	Lloyd	2	-	-	-	One-time	-	$0	$0	$0	$0
8	Lloyd	3	-	-	-	One-time	-	$0	$0	$0	$0
9	Lloyd	4	-	-	-	Capital	-	$0	$0	$0	$0
10	Lakeview	1	-	-	-	One-time	-	$0	$0	$0	$0
11	Lakeview	2	-	-	-	One-time	-	$0	$0	$0	$0
12	Lakeview	3	-	-	-	Capital	-	$0	$0	$0	$0
13	Lakeview	4	-	-	-	One-time	-	$0	$0	$0	$0
14	Lakeview	5	-	-	-	Capital	-	$0	$0	$0	$0
15	Los Flores	1	-	-	-	One-time	-	$0	$0	$0	$0
16	Los Flores	2	-	-	-	One-time	-	$0	$0	$0	$0
17	Los Flores	3	There is no regular program of flow line maintenance for each flow line at Los Flores to reduce the likelihood of a discharge. (40 CFR 112.1b, 112,7e, and 112,9d and API 570)	8/31/2002	5/20/2010	Every 5 years	$32,565	$0	$0	$0	$0
18	Los Flores	4	-	-	-	One-time	-	$0	$0	$0	$0
19	Los Flores	5	-	-	-	capital	-	$0	$0	$0	$0
20	Los Flores	6	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,719	$1,857	$1,792	$1,751
21	Los Flores	7	-	-	-	capital	-	$0	$0	$0	$0
22	Bell	1	-	-	-	one-time	-	$0	$0	$0	$0
23	Bell	2	-	-	-	one-time	-	$0	$0	$0	$0

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Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	Y	Z	AA	AB
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2014	12/31/2015	12/31/2016	12/31/2017
1	Williams B	1	-	-	-	One-time	-	$0	$0	$0	$0
2	Williams B	2	There is no regular program of flow line maintenance for each flow line at Williams B to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	6/30/2000	2/25/2010	Biennial	$98,744	$0	$0	$0	$0
3	Williams B	3	-	-	-	One-time	-	$0	$0	$0	$0
4	Williams B	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	6/30/2000	2/25/2010	Annual	$1,185	$0	$0	$0	$0
5	Williams B	5	-	-	-	Capital	-	$0	$0	$0	$0
6	Lloyd	1	-	-	-	One-time	-	$0	$0	$0	$0
7	Lloyd	2	-	-	-	One-time	-	$0	$0	$0	$0
8	Lloyd	3	-	-	-	One-time	-	$0	$0	$0	$0
9	Lloyd	4	-	-	-	Capital	-	$0	$0	$0	$0
10	Lakeview	1	-	-	-	One-time	-	$0	$0	$0	$0
11	Lakeview	2	-	-	-	One-time	-	$0	$0	$0	$0
12	Lakeview	3	-	-	-	Capital	-	$0	$0	$0	$0
13	Lakeview	4	-	-	-	One-time	-	$0	$0	$0	$0
14	Lakeview	5	-	-	-	Capital	-	$0	$0	$0	$0
15	Los Flores	1	-	-	-	One-time	-	$0	$0	$0	$0
16	Los Flores	2	-	-	-	One-time	-	$0	$0	$0	$0
17	Los Flores	3	There is no regular program of flow line maintenance for each flow line at Los Flores to reduce the likelihood of a discharge. (40 CFR 112.1b, 112,7e, and 112,9d and API 570)	8/31/2002	5/20/2010	Every 5 years	$32,565	$0	$0	$0	$0
18	Los Flores	4	-	-	-	One-time	-	$0	$0	$0	$0
19	Los Flores	5	-	-	-	capital	-	$0	$0	$0	$0
20	Los Flores	6	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,797	$1,716	$1,682	$0
21	Los Flores	7	-	-	-	capital	-	$0	$0	$0	$0
22	Bell	1	-	-	-	one-time	-	$0	$0	$0	$0
23	Bell	2	-	-	-	one-time	-	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	I	J	K	L
								Present value of cost estimate as of Dec. 31 of initial non-comp			
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/1998	12/31/1999	12/31/2000	12/31/2001
24	Bell	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.)	11/30/1999	1/11/2010	Every 5 years	$209,191	$0	$210,970	$0	$0
25	Bell	4a	-	-	-	one-time	-	$0	$0	$0	$0
26	Bell	4b	-	-	-	one-time	-	$0	$0	$0	$0
27	Bell	4c	-	-	-	one-time	-	$0	$0	$0	$0
28	Bell	4d	-	-	-	one-time	-	$0	$0	$0	$0
29	Bell	4f	-	-	-	one-time	-	$0	$0	$0	$0
30	Bell	4g	-	-	-	one-time	-	$0	$0	$0	$0
31	Bell	4h	-	-	-	one-time	-	$0	$0	$0	$0
32	Bell	5	-	-	-	capital	-	$0	$0	$0	$0
33	Bell	6	-	-	-	Capital	-	$0	$0	$0	$0
34	Bell	7	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$0	$1,191	$1,204	$1,193
35	Bell	8	-	-	-	capital	-	$0	$0	$0	$0
36	Chamberlin	1	-	-	-	one-time	-	$0	$0	$0	$0
37	Chamberlin	2	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	2/17/2011	Every 5 years	$17,535	$0	$0	$0	$0
38	Chamberlin	3	-	-	-	capital	-	$0	$0	$0	$0
39	Chamberlin	4	-	-	-	capital	-	$0	$0	$0	$0
40	Chamberlin	5	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$0	$0	$0	$0
41	Davis	1	-	-	-	one-time	-	$0	$0	$0	$0
42	Davis	2	-	-	-	one-time	-	$0	$0	$0	$0
43	Davis	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40	8/31/2002	3/9/2011	Biennial	$5,010	$0	$0	$0	$0
44	Davis	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 28 other lines.	8/31/2002	3/9/2011	Every 5 years	$70,141	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	M	N	O	P
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2002	12/31/2003	12/31/2004	12/31/2005
24	Bell	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.)	11/30/1999	1/11/2010	Every 5 years	$209,191	$0	$0	$248,702	$0
25	Bell	4a	-	-	-	one-time	-	$0	$0	$0	$0
26	Bell	4b	-	-	-	one-time	-	$0	$0	$0	$0
27	Bell	4c	-	-	-	one-time	-	$0	$0	$0	$0
28	Bell	4d	-	-	-	one-time	-	$0	$0	$0	$0
29	Bell	4f	-	-	-	one-time	-	$0	$0	$0	$0
30	Bell	4g	-	-	-	one-time	-	$0	$0	$0	$0
31	Bell	4h	-	-	-	one-time	-	$0	$0	$0	$0
32	Bell	5	-	-	-	capital	-	$0	$0	$0	$0
33	Bell	6	-	-	-	Capital	-	$0	$0	$0	$0
34	Bell	7	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,213	$1,237	$1,404	$1,439
35	Bell	8	-	-	-	capital	-	$0	$0	$0	$0
36	Chamberlin	1	-	-	-	one-time	-	$0	$0	$0	$0
37	Chamberlin	2	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	2/17/2011	Every 5 years	$17,535	$18,173	$0	$0	$0
38	Chamberlin	3	-	-	-	capital	-	$0	$0	$0	$0
39	Chamberlin	4	-	-	-	capital	-	$0	$0	$0	$0
40	Chamberlin	5	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,246	$1,252	$1,419	$1,432
41	Davis	1	-	-	-	one-time	-	$0	$0	$0	$0
42	Davis	2	-	-	-	one-time	-	$0	$0	$0	$0
43	Davis	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40	8/31/2002	3/9/2011	Biennial	$5,010	$5,192	$0	$5,911	$0
44	Davis	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 28 other lines.	8/31/2002	3/9/2011	Every 5 years	$70,141	$72,694	$0	$0	$0

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	Q	R	S	T	U
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010
24	Bell	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.)	11/30/1999	1/11/2010	Every 5 years	$209,191	$0	$0	$0	$282,648	$0
25	Bell	4a	-	-	-	one-time	-	$0	$0	$0	$0	$0
26	Bell	4b	-	-	-	one-time	-	$0	$0	$0	$0	$0
27	Bell	4c	-	-	-	one-time	-	$0	$0	$0	$0	$0
28	Bell	4d	-	-	-	one-time	-	$0	$0	$0	$0	$0
29	Bell	4f	-	-	-	one-time	-	$0	$0	$0	$0	$0
30	Bell	4g	-	-	-	one-time	-	$0	$0	$0	$0	$0
31	Bell	4h	-	-	-	one-time	-	$0	$0	$0	$0	$0
32	Bell	5	-	-	-	capital	-	$0	$0	$0	$0	$0
33	Bell	6	-	-	-	Capital	-	$0	$0	$0	$0	$0
34	Bell	7	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,554	$1,597	$1,722	$1,596	$1,694
35	Bell	8	-	-	-	capital	-	$0	$0	$0	$0	$0
36	Chamberlin	1	-	-	-	one-time	-	$0	$0	$0	$0	$0
37	Chamberlin	2	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	2/17/2011	Every 5 years	$17,535	$0	$24,046	$0	$0	$0
38	Chamberlin	3	-	-	-	capital	-	$0	$0	$0	$0	$0
39	Chamberlin	4	-	-	-	capital	-	$0	$0	$0	$0	$0
40	Chamberlin	5	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112 9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,587	$1,649	$1,933	$1,639	$1,719
41	Davis	1	-	-	-	one-time	-	$0	$0	$0	$0	$0
42	Davis	2	-	-	-	one-time	-	$0	$0	$0	$0	$0
43	Davis	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40	8/31/2002	3/9/2011	Biennial	$5,010	$6,612	$0	$8,052	$0	$7,161
44	Davis	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 28 other lines.	8/31/2002	3/9/2011	Every 5 years	$70,141	$0	$96,185	$0	$0	$0

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	V	W	X	Y
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2011	12/31/2012	12/31/2013	12/31/2014
24	Bell	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.)	11/30/1999	1/11/2010	Every 5 years	$209,191	$0	$0	$0	$0
25	Bell	4a	-	-	-	one-time	-	$0	$0	$0	$0
26	Bell	4b	-	-	-	one-time	-	$0	$0	$0	$0
27	Bell	4c	-	-	-	one-time	-	$0	$0	$0	$0
28	Bell	4d	-	-	-	one-time	-	$0	$0	$0	$0
29	Bell	4f	-	-	-	one-time	-	$0	$0	$0	$0
30	Bell	4g	-	-	-	one-time	-	$0	$0	$0	$0
31	Bell	4h	-	-	-	one-time	-	$0	$0	$0	$0
32	Bell	5	-	-	-	capital	-	$0	$0	$0	$0
33	Bell	6	-	-	-	Capital	-	$0	$0	$0	$0
34	Bell	7	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,796	$1,733	$1,720	$1,757
35	Bell	8	-	-	-	capital	-	$0	$0	$0	$0
36	Chamberlin	1	-	-	-	one-time	-	$0	$0	$0	$0
37	Chamberlin	2	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	2/17/2011	Every 5 years	$17,535	$0	$0	$0	$0
38	Chamberlin	3	-	-	-	capital	-	$0	$0	$0	$0
39	Chamberlin	4	-	-	-	capital	-	$0	$0	$0	$0
40	Chamberlin	5	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,857	$1,792	$1,751	$1,797
41	Davis	1	-	-	-	one-time	-	$0	$0	$0	$0
42	Davis	2	-	-	-	one-time	-	$0	$0	$0	$0
43	Davis	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40	8/31/2002	3/9/2011	Biennial	$5,010	$0	$0	$0	$0
44	Davis	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 28 other lines.	8/31/2002	3/9/2011	Every 5 years	$70,141	$0	$0	$0	$0

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Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	Z	AA	AB
Row	**Lease**	**Item No.**	**Item Description**	**Date of initial non-compliance**	**Date recurring costs incurred ("avoided through")**	**Type of cost (capital, one-time, annual)**	**Cost estimate as of initial non-compliance date**	**12/31/2015**	**12/31/2016**	**12/31/2017**
24	Bell	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.)	11/30/1999	1/11/2010	Every 5 years	$209,191	$0	$0	$0
25	Bell	4a	-	-	-	one-time	-	$0	$0	$0
26	Bell	4b	-	-	-	one-time	-	$0	$0	$0
27	Bell	4c	-	-	-	one-time	-	$0	$0	$0
28	Bell	4d	-	-	-	one-time	-	$0	$0	$0
29	Bell	4f	-	-	-	one-time	-	$0	$0	$0
30	Bell	4g	-	-	-	one-time	-	$0	$0	$0
31	Bell	4h	-	-	-	one-time	-	$0	$0	$0
32	Bell	5	-	-	-	capital	-	$0	$0	$0
33	Bell	6	-	-	-	Capital	-	$0	$0	$0
34	Bell	7	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems to be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,648	$1,652	$0
35	Bell	8	-	-	-	capital	-	$0	$0	$0
36	Chamberlin	1	-	-	-	one-time	-	$0	$0	$0
37	Chamberlin	2	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	2/17/2011	Every 5 years	$17,535	$0	$0	$0
38	Chamberlin	3	-	-	-	capital	-	$0	$0	$0
39	Chamberlin	4	-	-	-	capital	-	$0	$0	$0
40	Chamberlin	5	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,716	$1,682	$0
41	Davis	1	-	-	-	one-time	-	$0	$0	$0
42	Davis	2	-	-	-	one-time	-	$0	$0	$0
43	Davis	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40	8/31/2002	3/9/2011	Biennial	$5,010	$0	$0	$0
44	Davis	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 28 other lines.	8/31/2002	3/9/2011	Every 5 years	$70,141	$0	$0	$0

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	I	J	K	L	M
								Present value of cost estimate as of Dec. 31 of initial non-compliance year:				
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/1998	12/31/1999	12/31/2000	12/31/2001	12/31/2002
45	Davis	5	-	-	-	capital	-	$0	$0	$0	$0	$0
46	Davis	6	-	-	-	capital	-	$0	$0	$0	$0	$0
47	Davis	7	-	-	-	One-time	-	$0	$0	$0	$0	$0
48	Davis	8	-	-	-	one-time	-	$0	$0	$0	$0	$0
49	Davis	9	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$0	$0	$0	$0	$1,246
50	Casmalia	1	-	-	-	One-time	-	$0	$0	$0	$0	$0
51	Casmalia	2	-	-	-	One-time	-	$0	$0	$0	$0	$0
52	Casmalia	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 1 line in environmentally sensitive area (ESA).	11/30/1999	7/18/2011	Biennial	$2,461	$0	$2,482	$0	$2,485	$0
53	Casmalia	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 35 other lines.	11/30/1999	7/18/2011	Every 5 years	$86,137	$0	$86,870	$0	$0	$0
54	Casmalia	5	-	-	-	capital	-	$0	$0	$0	$0	$0
55	Casmalia	6	-	-	-	capital	-	$0	$0	$0	$0	$0
56	Casmalia	7	The Santa Barbara County Fire Department tested the alarm system at the tank battery which failed. Greka should perform regular tests on the alarm system to ensure its proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	2/12/2008	6/20/2017	Annual	$1,627	$0	$0	$0	$0	$0
57	Security	1	-	-	-	One-time	-	$0	$0	$0	$0	$0
58	Security	2	-	-	-	One-time	-	$0	$0	$0	$0	$0
59	Security	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge (i.e., integrity of flow lines at the Waste Oil Tank and around the LCR tanks appeared compromised due to erosion and neglect at time of EPA inspection in 2008). (40 CFR 112.1b, 40 CFR 112.7(e), 40 CFR 112.9(d), and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flow line.)	8/31/2002	6/10/2009	Every 5 years	$82,666	$0	$0	$0	$0	$85,675

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	N	O	P	Q	R
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2003	12/31/2004	12/31/2005	12/31/2006	12/31/2007
45	Davis	5	-	-	-	capital	-	$0	$0	$0	$0	$0
46	Davis	6	-	-	-	capital	-	$0	$0	$0	$0	$0
47	Davis	7	-	-	-	One-time	-	$0	$0	$0	$0	$0
48	Davis	8	-	-	-	one-time	-	$0	$0	$0	$0	$0
49	Davis	9	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,252	$1,419	$1,432	$1,587	$1,649
50	Casmalia	1	-	-	-	One-time	-	$0	$0	$0	$0	$0
51	Casmalia	2	-	-	-	One-time	-	$0	$0	$0	$0	$0
52	Casmalia	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 1 line in environmentally sensitive area (ESA).	11/30/1999	7/18/2011	Biennial	$2,461	$2,578	$0	$2,998	$0	$3,327
53	Casmalia	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 35 other lines.	11/30/1999	7/18/2011	Every 5 years	$86,137	$0	$102,407	$0	$0	$0
54	Casmalia	5	-	-	-	capital	-	$0	$0	$0	$0	$0
55	Casmalia	6	-	-	-	capital	-	$0	$0	$0	$0	$0
56	Casmalia	7	The Santa Barbara County Fire Department tested the alarm system at the tank battery which failed. Greka should perform regular tests on the alarm system to ensure its proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	2/12/2008	6/20/2017	Annual	$1,627	$0	$0	$0	$0	$0
57	Security	1	-	-	-	One-time	-	$0	$0	$0	$0	$0
58	Security	2	-	-	-	One-time	-	$0	$0	$0	$0	$0
59	Security	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge (i.e., integrity of flow lines at the Waste Oil Tank and around the LCR tanks appeared compromised due to erosion and neglect at time of EPA inspection in 2008). (40 CFR 112.1b, 40 CFR 112.7(e), 40 CFR 112.9(d), and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flow line.)	8/31/2002	6/10/2009	Every 5 years	$82,666	$0	$0	$0	$0	$113,360

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	S	T	U	V	W	X
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013
45	Davis	5	-	-	-	capital	-	$0	$0	$0	$0	$0	$0
46	Davis	6	-	-	-	capital	-	$0	$0	$0	$0	$0	$0
47	Davis	7	-	-	-	One-time	-	$0	$0	$0	$0	$0	$0
48	Davis	8	-	-	-	one-time	-	$0	$0	$0	$0	$0	$0
49	Davis	9	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,933	$1,639	$1,719	$1,857	$1,792	$1,751
50	Casmalia	1	-	-	-	One-time	-	$0	$0	$0	$0	$0	$0
51	Casmalia	2	-	-	-	One-time	-	$0	$0	$0	$0	$0	$0
52	Casmalia	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128 d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 1 line in environmentally sensitive area (ESA).	11/30/1999	7/18/2011	Biennial	$2,461	$0	$3,325	$0	$0	$0	$0
53	Casmalia	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128 d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 35 other lines.	11/30/1999	7/18/2011	Every 5 years	$86,137	$0	$116,384	$0	$0	$0	$0
54	Casmalia	5	-	-	-	capital	-	$0	$0	$0	$0	$0	$0
55	Casmalia	6	-	-	-	capital	-	$0	$0	$0	$0	$0	$0
56	Casmalia	7	The Santa Barbara County Fire Department tested the alarm system at the tank battery which failed. Greka should perform regular tests on the alarm system to ensure its proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	2/12/2008	6/20/2017	Annual	$1,627	$1,783	$1,789	$1,791	$1,889	$1,948	$1,851
57	Security	1	-	-	-	One-time	-	$0	$0	$0	$0	$0	$0
58	Security	2	-	-	-	One-time	-	$0	$0	$0	$0	$0	$0
59	Security	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge (i.e., integrity of flow lines at the Waste Oil Tank and around the LCR tanks appeared compromised due to erosion and neglect at time of EPA inspection in 2008). (40 CFR 112.1b, 40 CFR 112.7(e), 40 CFR 112 9(d), and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flow line.)	8/31/2002	6/10/2009	Every 5 years	$82,666	$0	$0	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	Y	Z	AA	AB
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2014	12/31/2015	12/31/2016	12/31/2017
45	Davis	5	-	-	-	capital	-	$0	$0	$0	$0
46	Davis	6	-	-	-	capital	-	$0	$0	$0	$0
47	Davis	7	-	-	-	One-time	-	$0	$0	$0	$0
48	Davis	8	-	-	-	one-time	-	$0	$0	$0	$0
49	Davis	9	Regular tests should be performed on alarm systems for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,797	$1,716	$1,682	$0
50	Casmalia	1	-	-	-	One-time	-	$0	$0	$0	$0
51	Casmalia	2	-	-	-	One-time	-	$0	$0	$0	$0
52	Casmalia	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 1 line in environmentally sensitive area (ESA).	11/30/1999	7/18/2011	Biennial	$2,461	$0	$0	$0	$0
53	Casmalia	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7d, 40 CFR 1128.d, and API 570 requires onshore oil production facilities to have a program of flow line maintenance to prevent discharges from each flowline.) Cost estmate for 35 other lines.	11/30/1999	7/18/2011	Every 5 years	$86,137	$0	$0	$0	$0
54	Casmalia	5	-	-	-	capital	-	$0	$0	$0	$0
55	Casmalia	6	-	-	-	capital	-	$0	$0	$0	$0
56	Casmalia	7	The Santa Barbara County Fire Department tested the alarm system at the tank battery which failed. Greka should perform regular tests on the alarm system to ensure its proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	2/12/2008	6/20/2017	Annual	$1,627	$1,875	$1,848	$1,753	$1,780
57	Security	1	-	-	-	One-time	-	$0	$0	$0	$0
58	Security	2	-	-	-	One-time	-	$0	$0	$0	$0
59	Security	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge (i.e., integrity of flow lines at the Waste Oil Tank and around the LCR tanks appeared compromised due to erosion and neglect at time of EPA inspection in 2008). (40 CFR 112.1b, 40 CFR 112.7(e), 40 CFR 112.9(d), and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flow line.)	8/31/2002	6/10/2009	Every 5 years	$82,666	$0	$0	$0	$0

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Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	I	J	K	L
								Present value of cost estimate as of Dec. 31 of initial non-comp			
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/1998	12/31/1999	12/31/2000	12/31/2001
60	Security	4	-	-	-	capital	-	$0	$0	$0	$0
61	Security	5	-	-	-	capital	-	$0	$0	$0	$0
62	Security	6	-	-	-	One-time	-	$0	$0	$0	$0
63	Security	7	-	-	-	capital	-	$0	$0	$0	$0
64	Security	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$0	$0	$0	$0
65	U-Cal	1	-	-	-	One-time	-	$0	$0	$0	$0
66	U-Cal	2	-	-	-	One-time	-	$0	$0	$0	$0
67	U-Cal	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	1/1/2009	Every 5 years	$102,706	$0	$0	$0	$0
68	U-Cal	4	-	-	-	capital	-	$0	$0	$0	$0
69	U-Cal	5	-	-	-	capital	-	$0	$0	$0	$0
70	U-Cal	6	-	-	-	capital	-	$0	$0	$0	$0
71	U-Cal	7	-	-	-	One-time	-	$0	$0	$0	$0
72	U-Cal	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	1/1/2009	Annual	$1,202	$0	$0	$0	$0
73	U-Cal	9	-	-	-	capital	-	$0	$0	$0	$0
74	U-Cal	10	-	-	-	capital	-	$0	$0	$0	$0
75	Escolle	1	-	-	-	One-time	-	$0	$0	$0	$0
76	Escolle	2	There is no regular program of flow line maintenance for each flow line at Lakeview to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	11/30/1999	3/23/2010	Every 5 years	$27,072	$0	$27,302	$0	$0
77	Escolle	3	-	-	-	One-time	-	$0	$0	$0	$0
78	Escolle	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to property identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$0	$1,191	$1,204	$1,193
79	Escolle	5	-	-	-	Capital	-	$0	$0	$0	$0
80	Battles	1	-	-	-	One-time	-	$0	$0	$0	$0
81	Battles	2	-	-	-	One-time	-	$0	$0	$0	$0

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Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	M	N	O	P
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2002	12/31/2003	12/31/2004	12/31/2005
60	Security	4	-	-	-	capital	-	$0	$0	$0	$0
61	Security	5	-	-	-	capital	-	$0	$0	$0	$0
62	Security	6	-	-	-	One-time	-	$0	$0	$0	$0
63	Security	7	-	-	-	capital	-	$0	$0	$0	$0
64	Security	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,246	$1,252	$1,419	$1,432
65	U-Cal	1	-	-	-	One-time	-	$0	$0	$0	$0
66	U-Cal	2	-	-	-	One-time	-	$0	$0	$0	$0
67	U-Cal	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	1/1/2009	Every 5 years	$102,706	$106,445	$0	$0	$0
68	U-Cal	4	-	-	-	capital	-	$0	$0	$0	$0
69	U-Cal	5	-	-	-	capital	-	$0	$0	$0	$0
70	U-Cal	6	-	-	-	capital	-	$0	$0	$0	$0
71	U-Cal	7	-	-	-	One-time	-	$0	$0	$0	$0
72	U-Cal	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	1/1/2009	Annual	$1,202	$1,246	$1,252	$1,419	$1,432
73	U-Cal	9	-	-	-	capital	-	$0	$0	$0	$0
74	U-Cal	10	-	-	-	capital	-	$0	$0	$0	$0
75	Escolle	1	-	-	-	One-time	-	$0	$0	$0	$0
76	Escolle	2	There is no regular program of flow line maintenance for each flow line at Lakeview to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	11/30/1999	3/23/2010	Every 5 years	$27,072	$0	$0	$32,185	$0
77	Escolle	3	-	-	-	One-time	-	$0	$0	$0	$0
78	Escolle	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to property identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,213	$1,237	$1,404	$1,439
79	Escolle	5	-	-	-	Capital	-	$0	$0	$0	$0
80	Battles	1	-	-	-	One-time	-	$0	$0	$0	$0
81	Battles	2	-	-	-	One-time	-	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	Q	R	S	T
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2006	12/31/2007	12/31/2008	12/31/2009
60	Security	4	-	-	-	capital	-	$0	$0	$0	$0
61	Security	5	-	-	-	capital	-	$0	$0	$0	$0
62	Security	6	-	-	-	One-time	-	$0	$0	$0	$0
63	Security	7	-	-	-	capital	-	$0	$0	$0	$0
64	Security	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,587	$1,649	$1,933	$1,639
65	U-Cal	1	-	-	-	One-time	-	$0	$0	$0	$0
66	U-Cal	2	-	-	-	One-time	-	$0	$0	$0	$0
67	U-Cal	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	1/1/2009	Every 5 years	$102,706	$0	$140,842	$0	$0
68	U-Cal	4	-	-	-	capital	-	$0	$0	$0	$0
69	U-Cal	5	-	-	-	capital	-	$0	$0	$0	$0
70	U-Cal	6	-	-	-	capital	-	$0	$0	$0	$0
71	U-Cal	7	-	-	-	One-time	-	$0	$0	$0	$0
72	U-Cal	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	1/1/2009	Annual	$1,202	$1,587	$1,649	$1,933	$0
73	U-Cal	9	-	-	-	capital	-	$0	$0	$0	$0
74	U-Cal	10	-	-	-	capital	-	$0	$0	$0	$0
75	Escolle	1	-	-	-	One-time	-	$0	$0	$0	$0
76	Escolle	2	There is no regular program of flow line maintenance for each flow line at Lakeview to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	11/30/1999	3/23/2010	Every 5 years	$27,072	$0	$0	$0	$36,578
77	Escolle	3	-	-	-	One-time	-	$0	$0	$0	$0
78	Escolle	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to property identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,554	$1,597	$1,722	$1,596
79	Escolle	5	-	-	-	Capital	-	$0	$0	$0	$0
80	Battles	1	-	-	-	One-time	-	$0	$0	$0	$0
81	Battles	2	-	-	-	One-time	-	$0	$0	$0	$0

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	U	V	W	X
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2010	12/31/2011	12/31/2012	12/31/2013
60	Security	4	-	-	-	capital	-	$0	$0	$0	$0
61	Security	5	-	-	-	capital	-	$0	$0	$0	$0
62	Security	6	-	-	-	One-time	-	$0	$0	$0	$0
63	Security	7	-	-	-	capital	-	$0	$0	$0	$0
64	Security	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,719	$1,857	$1,792	$1,751
65	U-Cal	1	-	-	-	One-time	-	$0	$0	$0	$0
66	U-Cal	2	-	-	-	One-time	-	$0	$0	$0	$0
67	U-Cal	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	1/1/2009	Every 5 years	$102,706	$0	$0	$0	$0
68	U-Cal	4	-	-	-	capital	-	$0	$0	$0	$0
69	U-Cal	5	-	-	-	capital	-	$0	$0	$0	$0
70	U-Cal	6	-	-	-	capital	-	$0	$0	$0	$0
71	U-Cal	7	-	-	-	One-time	-	$0	$0	$0	$0
72	U-Cal	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	1/1/2009	Annual	$1,202	$0	$0	$0	$0
73	U-Cal	9	-	-	-	capital	-	$0	$0	$0	$0
74	U-Cal	10	-	-	-	capital	-	$0	$0	$0	$0
75	Escolle	1	-	-	-	One-time	-	$0	$0	$0	$0
76	Escolle	2	There is no regular program of flow line maintenance for each flow line at Lakeview to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	11/30/1999	3/23/2010	Every 5 years	$27,072	$0	$0	$0	$0
77	Escolle	3	-	-	-	One-time	-	$0	$0	$0	$0
78	Escolle	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to property identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,694	$1,796	$1,733	$1,720
79	Escolle	5	-	-	-	Capital	-	$0	$0	$0	$0
80	Battles	1	-	-	-	One-time	-	$0	$0	$0	$0
81	Battles	2	-	-	-	One-time	-	$0	$0	$0	$0

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Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	Y	Z	AA	AB
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2014	12/31/2015	12/31/2016	12/31/2017
60	Security	4	-	-	-	capital	-	$0	$0	$0	$0
61	Security	5	-	-	-	capital	-	$0	$0	$0	$0
62	Security	6	-	-	-	One-time	-	$0	$0	$0	$0
63	Security	7	-	-	-	capital	-	$0	$0	$0	$0
64	Security	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operation. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	6/20/2017	Annual	$1,202	$1,797	$1,716	$1,682	$0
65	U-Cal	1	-	-	-	One-time	-	$0	$0	$0	$0
66	U-Cal	2	-	-	-	One-time	-	$0	$0	$0	$0
67	U-Cal	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.)	8/31/2002	1/1/2009	Every 5 years	$102,706	$0	$0	$0	$0
68	U-Cal	4	-	-	-	capital	-	$0	$0	$0	$0
69	U-Cal	5	-	-	-	capital	-	$0	$0	$0	$0
70	U-Cal	6	-	-	-	capital	-	$0	$0	$0	$0
71	U-Cal	7	-	-	-	One-time	-	$0	$0	$0	$0
72	U-Cal	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	8/31/2002	1/1/2009	Annual	$1,202	$0	$0	$0	$0
73	U-Cal	9	-	-	-	capital	-	$0	$0	$0	$0
74	U-Cal	10	-	-	-	capital	-	$0	$0	$0	$0
75	Escolle	1	-	-	-	One-time	-	$0	$0	$0	$0
76	Escolle	2	There is no regular program of flow line maintenance for each flow line at Lakeview to reduce the likelihood of a discharge. (40 CFR 112.1b. 112,7e, and 112.9d, and API 570)	11/30/1999	3/23/2010	Every 5 years	$27,072	$0	$0	$0	$0
77	Escolle	3	-	-	-	One-time	-	$0	$0	$0	$0
78	Escolle	4	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to property identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,757	$1,648	$1,652	$0
79	Escolle	5	-	-	-	Capital	-	$0	$0	$0	$0
80	Battles	1	-	-	-	One-time	-	$0	$0	$0	$0
81	Battles	2	-	-	-	One-time	-	$0	$0	$0	$0

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Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	I	J	K	L
								Present value of cost estimate as of Dec. 31 of initial non-comp			
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/1998	12/31/1999	12/31/2000	12/31/2001
82	Battles	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 3 lines in environmentally sensitive areas (ESA).	11/30/1999	2/22/2010	Biennial	$7,383	$0	$7,446	$0	$7,455
83	Battles	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 23 other lines.	11/30/1999	2/22/2010	Every 5 years	$56,604	$0	$57,086	$0	$0
84	Battles	5	-	-	-	capital	-	$0	$0	$0	$0
85	Battles	6	-	-	-	capital	-	$0	$0	$0	$0
86	Battles	7	-	-	-	One-time	-	$0	$0	$0	$0
87	Battles	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$0	$1,191	$1,204	$1,193
							SUM	$0	$395,731	$109,219	$14,772

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	M	N	O	P
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2002	12/31/2003	12/31/2004	12/31/2005
82	Battles	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 3 lines in environmentally sensitive areas (ESA).	11/30/1999	2/22/2010	Biennial	$7,383	$0	$7,733	$0	$8,994
83	Battles	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 23 other lines.	11/30/1999	2/22/2010	Every 5 years	$56,604	$0	$0	$67,296	$0
84	Battles	5	-	-	-	capital	-	$0	$0	$0	$0
85	Battles	6	-	-	-	capital	-	$0	$0	$0	$0
86	Battles	7	-	-	-	One-time	-	$0	$0	$0	$0
87	Battles	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,213	$1,237	$1,404	$1,439
							SUM	**$438,150**	**$21,543**	**$585,350**	**$24,937**

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Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	Q	R	S	T
Row	**Lease**	**Item No.**	**Item Description**	**Date of initial non-compliance**	**Date recurring costs incurred ("avoided through")**	**Type of cost (capital, one-time, annual)**	**Cost estimate as of initial non-compliance date**	**12/31/2006**	**12/31/2007**	**12/31/2008**	**12/31/2009**
82	Battles	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 3 lines in environmentally sensitive areas (ESA).	11/30/1999	2/22/2010	Biennial	$7,383	$0	$9,982	$0	$9,976
83	Battles	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 23 other lines.	11/30/1999	2/22/2010	Every 5 years	$56,604	$0	$0	$0	$76,481
84	Battles	5	-	-	-	capital	-	$0	$0	$0	$0
85	Battles	6	-	-	-	capital	-	$0	$0	$0	$0
86	Battles	7	-	-	-	One-time	-	$0	$0	$0	$0
87	Battles	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,554	$1,597	$1,722	$1,596
							SUM	**$153,244**	**$447,113**	**$184,591**	**$540,169**

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Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	U	V	W	X
Row	**Lease**	**Item No.**	**Item Description**	**Date of initial non-compliance**	**Date recurring costs incurred ("avoided through")**	**Type of cost (capital, one-time, annual)**	**Cost estimate as of initial non-compliance date**	**12/31/2010**	**12/31/2011**	**12/31/2012**	**12/31/2013**
82	Battles	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 3 lines in environmentally sensitive areas (ESA).	11/30/1999	2/22/2010	Biennial	$7,383	$0	$0	$0	$0
83	Battles	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 23 other lines.	11/30/1999	2/22/2010	Every 5 years	$56,604	$0	$0	$0	$0
84	Battles	5	-	-	-	capital	-	$0	$0	$0	$0
85	Battles	6	-	-	-	capital	-	$0	$0	$0	$0
86	Battles	7	-	-	-	One-time	-	$0	$0	$0	$0
87	Battles	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,694	$1,796	$1,733	$1,720
							SUM	**$20,908**	**$14,703**	**$14,314**	**$14,016**

Appendix B: Avoided Recurring Costs – PV Year End

A	B	C	D	E	F	G	H	Y	Z	AA	AB
Row	Lease	Item No.	Item Description	Date of initial non-compliance	Date recurring costs incurred ("avoided through")	Type of cost (capital, one-time, annual)	Cost estimate as of initial non-compliance date	12/31/2014	12/31/2015	12/31/2016	12/31/2017
82	Battles	3	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 3 lines in environmentally sensitive areas (ESA).	11/30/1999	2/22/2010	Biennial	$7,383	$0	$0	$0	$0
83	Battles	4	There is no regular program of flow line maintenance for each flow line to reduce the likelihood of a discharge. (40 CFR 112.7e, 40 CFR 112.9d, and API 570 requires onshore oil production facilities to have a program of flowline maintenance to prevent discharges from each flowline.) Cost estimate for 23 other lines.	11/30/1999	2/22/2010	Every 5 years	$56,604	$0	$0	$0	$0
84	Battles	5	-	-	-	capital	-	$0	$0	$0	$0
85	Battles	6	-	-	-	capital	-	$0	$0	$0	$0
86	Battles	7	-	-	-	One-time	-	$0	$0	$0	$0
87	Battles	8	Regular tests should be performed on the alarm system for the tanks to ensure proper operations. (40 CFR 112.9c requires sensor/alarm systems be designed to prevent discharges and 40 CFR 112.7e to properly identify problems requiring correction at the facility.)	11/30/1999	6/20/2017	Annual	$1,181	$1,757	$1,648	$1,652	$0
							SUM	**$14,334**	**$13,655**	**$13,438**	**$1,780**

Notes by column:

[A] - [H] Reproduced from "Cost Inputs" table for recurring costs only.

[I] - [AB] Nominal cost estimates from "Recurring Costs - Nominal" are inflated to Dec. 31 of the corresponding year, using WACC values from "Other Inputs." Equal to [nominal cost] * (1 + WACC)^(portion of year between non-compliance date and Dec. 31 of that year).

Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	H	I	J	K	L
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	NPV adjustment for year-end	12/31/1998	12/31/1999	12/31/2000	12/31/2001
1	Williams B	1	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
2	Williams B	2	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
3	Williams B	3	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
4	Williams B	4	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
5	Williams B	5	The secondary containment around the tanks and production equipment was not present or were compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/30/2000	$1,974.88	$2,087.10	$0.00	$0.00	$282.21	$483.65
6	Lloyd	1	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
7	Lloyd	2	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
8	Lloyd	3	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
9	Lloyd	4	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	8/31/2002	$1,202.41	$1,246.18	$0.00	$0.00	$0.00	$0.00
10	Lakeview	1	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
11	Lakeview	2	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
12	Lakeview	3	Two tanks were observed outside of secondary containment at the Lakeview facility.	7	8/31/2002	$2,004.02	$2,076.97	$0.00	$0.00	$0.00	$0.00
13	Lakeview	4	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
14	Lakeview	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	8/31/2002	$1,202.41	$1,246.18	$0.00	$0.00	$0.00	$0.00
15	Los Flores	1	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
16	Los Flores	2	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
17	Los Flores	3	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
18	Los Flores	4	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
19	Los Flores	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$1,246.18	$0.00	$0.00	$0.00	$0.00
20	Los Flores	6	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
21	Los Flores	7	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c)	7	8/31/2002	$1,202.41	$1,246.18	$0.00	$0.00	$0.00	$0.00
22	Bell	1	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
23	Bell	2	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
24	Bell	3	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
25	Bell	4a	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
26	Bell	4b	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
27	Bell	4c	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00

Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	M	N	O	P	Q
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	12/31/2002	12/31/2003	12/31/2004	12/31/2005	12/31/2006
1	Williams B	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
2	Williams B	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
3	Williams B	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
4	Williams B	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
5	Williams B	5	The secondary containment around the tanks and production equipment was not present or were compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/30/2000	$1,974.88	$345.41	$246.66	$176.36	$176.16	$176.36
6	Lloyd	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
7	Lloyd	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
8	Lloyd	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
9	Lloyd	4	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	8/31/2002	$1,202.41	$481.00	$206.13	$147.21	$105.13	$75.16
10	Lakeview	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
11	Lakeview	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
12	Lakeview	3	Two tanks were observed outside of secondary containment at the Lakeview facility.	7	8/31/2002	$2,004.02	$801.67	$343.55	$245.35	$175.21	$125.27
13	Lakeview	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
14	Lakeview	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	8/31/2002	$1,202.41	$481.00	$206.13	$147.21	$105.13	$75.16
15	Los Flores	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
16	Los Flores	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
17	Los Flores	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
18	Los Flores	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
19	Los Flores	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$481.00	$206.13	$147.21	$105.13	$75.16
20	Los Flores	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
21	Los Flores	7	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c)	7	8/31/2002	$1,202.41	$481.00	$206.13	$147.21	$105.13	$75.16
22	Bell	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
23	Bell	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
24	Bell	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
25	Bell	4a	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
26	Bell	4b	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
27	Bell	4c	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00

Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	R	S	T	U	V
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011
1	Williams B	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
2	Williams B	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
3	Williams B	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
4	Williams B	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
5	Williams B	5	The secondary containment around the tanks and production equipment was not present or were compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/30/2000	$1,974.88	$88.08	$0.00	$0.00	$0.00	$0.00
6	Lloyd	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
7	Lloyd	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
8	Lloyd	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
9	Lloyd	4	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	8/31/2002	$1,202.41	$75.08	$75.16	$37.54	$0.00	$0.00
10	Lakeview	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
11	Lakeview	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
12	Lakeview	3	Two tanks were observed outside of secondary containment at the Lakeview facility.	7	8/31/2002	$2,004.02	$125.13	$125.27	$62.57	$0.00	$0.00
13	Lakeview	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
14	Lakeview	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	8/31/2002	$1,202.41	$75.08	$75.16	$37.54	$0.00	$0.00
15	Los Flores	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
16	Los Flores	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
17	Los Flores	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
18	Los Flores	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
19	Los Flores	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$75.08	$75.16	$37.54	$0.00	$0.00
20	Los Flores	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
21	Los Flores	7	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c)	7	8/31/2002	$1,202.41	$75.08	$75.16	$37.54	$0.00	$0.00
22	Bell	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
23	Bell	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
24	Bell	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
25	Bell	4a	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
26	Bell	4b	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
27	Bell	4c	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00

Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	W	X	Y	Z	AA	AB
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017
1	Williams B	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	Williams B	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	Williams B	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
4	Williams B	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
5	Williams B	5	The secondary containment around the tanks and production equipment was not present or were compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/30/2000	$1,974.88	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	Lloyd	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
7	Lloyd	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
8	Lloyd	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
9	Lloyd	4	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	8/31/2002	$1,202.41	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
10	Lakeview	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
11	Lakeview	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
12	Lakeview	3	Two tanks were observed outside of secondary containment at the Lakeview facility.	7	8/31/2002	$2,004.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
13	Lakeview	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
14	Lakeview	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	8/31/2002	$1,202.41	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
15	Los Flores	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
16	Los Flores	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
17	Los Flores	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
18	Los Flores	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
19	Los Flores	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
20	Los Flores	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
21	Los Flores	7	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c)	7	8/31/2002	$1,202.41	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
22	Bell	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
23	Bell	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
24	Bell	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
25	Bell	4a	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
26	Bell	4b	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
27	Bell	4c	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	H	I	J	K	L
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	NPV adjustment for year-end	12/31/1998	12/31/1999	12/31/2000	12/31/2001
28	Bell	4d	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
29	Bell	4f	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
30	Bell	4g	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
31	Bell	4h	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$1,191.36	$0.00	$168.81	$289.30	$206.61
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$1,191.36	$0.00	$168.81	$289.30	$206.61
34	Bell	7	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	7	12/7/2007	$5,275.06	$5,305.00	$0.00	$0.00	$0.00	$0.00
36	Chamberlin	1	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
37	Chamberlin	2	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$1,246.18	$0.00	$0.00	$0.00	$0.00
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$1,246.18	$0.00	$0.00	$0.00	$0.00
40	Chamberlin	5	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
41	Davis	1	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
42	Davis	2	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
43	Davis	3	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
44	Davis	4	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$1,246.18	$0.00	$0.00	$0.00	$0.00
46	Davis	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$1,246.18	$0.00	$0.00	$0.00	$0.00

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Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	M	N	O	P	Q
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	12/31/2002	12/31/2003	12/31/2004	12/31/2005	12/31/2006
28	Bell	4d	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
29	Bell	4f	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
30	Bell	4g	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
31	Bell	4h	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$147.55	$105.49	$105.37	$105.49	$52.69
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$147.55	$105.49	$105.37	$105.49	$52.69
34	Bell	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	7	12/7/2007	$5,275.06	$0.00	$0.00	$0.00	$0.00	$0.00
36	Chamberlin	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
37	Chamberlin	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$481.00	$206.13	$147.21	$105.13	$75.16
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$481.00	$206.13	$147.21	$105.13	$75.16
40	Chamberlin	5	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
41	Davis	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
42	Davis	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
43	Davis	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
44	Davis	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$481.00	$206.13	$147.21	$105.13	$75.16
46	Davis	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$481.00	$206.13	$147.21	$105.13	$75.16

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Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	R	S	T	U	V
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011
28	Bell	4d	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
29	Bell	4f	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
30	Bell	4g	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
31	Bell	4h	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$0.00	$0.00	$0.00	$0.00	$0.00
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$0.00	$0.00	$0.00	$0.00	$0.00
34	Bell	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	7	12/7/2007	$5,275.06	$753.81	$1,291.86	$922.61	$658.85	$471.06
36	Chamberlin	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
37	Chamberlin	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$75.08	$75.16	$37.54	$0.00	$0.00
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$75.08	$75.16	$37.54	$0.00	$0.00
40	Chamberlin	5	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
41	Davis	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
42	Davis	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
43	Davis	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
44	Davis	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$75.08	$75.16	$37.54	$0.00	$0.00
46	Davis	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$75.08	$75.16	$37.54	$0.00	$0.00

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Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	W	X	Y	Z	AA	AB
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017
28	Bell	4d	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
29	Bell	4f	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
30	Bell	4g	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
31	Bell	4h	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
34	Bell	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	7	12/7/2007	$5,275.06	$470.54	$471.06	$235.27	$0.00	$0.00	$0.00
36	Chamberlin	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
37	Chamberlin	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
40	Chamberlin	5	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
41	Davis	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
42	Davis	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
43	Davis	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
44	Davis	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
46	Davis	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	H	I	J	K	L
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	NPV adjustment for year-end	12/31/1998	12/31/1999	12/31/2000	12/31/2001
47	Davis	7	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
48	Davis	8	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
49	Davis	9	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
50	Casmalia	1	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
51	Casmalia	2	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
52	Casmalia	3	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
53	Casmalia	4	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
54	Casmalia	5	Secondary containment of the tank battery was compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$1,191.36	$0.00	$168.81	$289.30	$206.61
55	Casmalia	6	Secondary containment of the wastewater pond was observed to be in a poor condition. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	11/30/1999	$1,181.31	$1,191.36	$0.00	$168.81	$289.30	$206.61
56	Casmalia	7	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
57	Security	1	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
58	Security	2	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
59	Security	3	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
60	Security	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires to provide appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$1,246.18	$0.00	$0.00	$0.00	$0.00
61	Security	5	Greka stored kerosene distillate (KD) to increase the viscosity of the heavy crude produced at the Security Lease. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. (40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contained spill oil.)	7	8/31/2002	$10,020.10	$10,384.84	$0.00	$0.00	$0.00	$0.00
62	Security	6	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
63	Security	7	The secondary containment around the LCR tanks and Waste Oil Tank are compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. An inspection of the Pumper's Weekly Lease Inspection forms were reviewed and these items were not identified in any of the past inspections by the pumper dating back to 2005. (40 CFR 112.7c require appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$1,246.18	$0.00	$0.00	$0.00	$0.00
64	Security	8	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
65	U-Cal	1	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
66	U-Cal	2	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00
67	U-Cal	3	-	-	-	-	-	$0.00	$0.00	$0.00	$0.00

Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	M	N	O	P	Q
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	12/31/2002	12/31/2003	12/31/2004	12/31/2005	12/31/2006
47	Davis	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
48	Davis	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
49	Davis	9	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
50	Casmalia	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
51	Casmalia	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
52	Casmalia	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
53	Casmalia	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
54	Casmalia	5	Secondary containment of the tank battery was compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$147.55	$105.49	$105.37	$105.49	$52.69
55	Casmalia	6	Secondary containment of the wastewater pond was observed to be in a poor condition. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	11/30/1999	$1,181.31	$147.55	$105.49	$105.37	$105.49	$52.69
56	Casmalia	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
57	Security	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
58	Security	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
59	Security	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
60	Security	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires to provide appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$481.00	$206.13	$147.21	$105.13	$75.16
61	Security	5	Greka stored kerosene distillate (KD) to increase the viscosity of the heavy crude produced at the Security Lease. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. (40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contained spill oil.)	7	8/31/2002	$10,020.10	$4,008.34	$1,717.74	$1,226.76	$876.06	$626.36
62	Security	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
63	Security	7	The secondary containment around the LCR tanks and Waste Oil Tank are compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. An inspection of the Pumper's Weekly Lease Inspection forms were reviewed and these items were not identified in any of the past inspections by the pumper dating back to 2005. (40 CFR 112.7c require appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$481.00	$206.13	$147.21	$105.13	$75.16
64	Security	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
65	U-Cal	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
66	U-Cal	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
67	U-Cal	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00

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Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	R	S	T	U	V
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011
47	Davis	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
48	Davis	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
49	Davis	9	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
50	Casmalia	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
51	Casmalia	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
52	Casmalia	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
53	Casmalia	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
54	Casmalia	5	Secondary containment of the tank battery was compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$0.00	$0.00	$0.00	$0.00	$0.00
55	Casmalia	6	Secondary containment of the wastewater pond was observed to be in a poor condition. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	11/30/1999	$1,181.31	$0.00	$0.00	$0.00	$0.00	$0.00
56	Casmalia	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
57	Security	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
58	Security	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
59	Security	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
60	Security	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires to provide appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$75.08	$75.16	$37.54	$0.00	$0.00
61	Security	5	Greka stored kerosene distillate (KD) to increase the viscosity of the heavy crude produced at the Security Lease. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. (40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contained spill oil.)	7	8/31/2002	$10,020.10	$625.65	$626.36	$312.83	$0.00	$0.00
62	Security	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
63	Security	7	The secondary containment around the LCR tanks and Waste Oil Tank are compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. An inspection of the Pumper's Weekly Lease Inspection forms were reviewed and these items were not identified in any of the past inspections by the pumper dating back to 2005. (40 CFR 112.7c require appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$75.08	$75.16	$37.54	$0.00	$0.00
64	Security	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
65	U-Cal	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
66	U-Cal	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
67	U-Cal	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00

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Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	W	X	Y	Z	AA	AB
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017
47	Davis	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
48	Davis	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
49	Davis	9	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
50	Casmalia	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
51	Casmalia	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
52	Casmalia	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
53	Casmalia	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
54	Casmalia	5	Secondary containment of the tank battery was compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
55	Casmalia	6	Secondary containment of the wastewater pond was observed to be in a poor condition. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	11/30/1999	$1,181.31	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
56	Casmalia	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
57	Security	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
58	Security	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
59	Security	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
60	Security	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires to provide appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
61	Security	5	Greka stored kerosene distillate (KD) to increase the viscosity of the heavy crude produced at the Security Lease. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. (40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contained spill oil.)	7	8/31/2002	$10,020.10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
62	Security	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
63	Security	7	The secondary containment around the LCR tanks and Waste Oil Tank are compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. An inspection of the Pumper's Weekly Lease Inspection forms were reviewed and these items were not identified in any of the past inspections by the pumper dating back to 2005. (40 CFR 112.7c require appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
64	Security	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
65	U-Cal	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
66	U-Cal	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
67	U-Cal	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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Appendix B: On-time – Capital Depreciation

A row	B lease	C Item #	D Description	E Depreciable life (years)	F Initial date of non-compliance	G Cost estimate as of non-compliance date	H NPV adjustment for year-end	I 12/31/1998	J 12/31/1999	K 12/31/2000
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$1,246.18	$0.00	$0.00	$0.00
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$1,246.18	$0.00	$0.00	$0.00
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	7	1/13/2005	$11,688.02	$12,702.02	$0.00	$0.00	$0.00
71	U-Cal	7	-	-	-	-	-	$0.00	$0.00	$0.00
72	U-Cal	8	-	-	-	-	-	$0.00	$0.00	$0.00
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	7	10/25/2005	$1,425.77	$1,448.53	$0.00	$0.00	$0.00
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	7	2/12/2008	$2,711.88	$2,972.32	$0.00	$0.00	$0.00
75	Escolle	1	-	-	-	-	-	$0.00	$0.00	$0.00
76	Escolle	2	-	-	-	-	-	$0.00	$0.00	$0.00
77	Escolle	3	-	-	-	-	-	$0.00	$0.00	$0.00
78	Escolle	4	-	-	-	-	-	$0.00	$0.00	$0.00
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	2/12/2008	$1,627.13	$1,783.39	$0.00	$0.00	$0.00
80	Battles	1	-	-	-	-	-	$0.00	$0.00	$0.00
81	Battles	2	-	-	-	-	-	$0.00	$0.00	$0.00
82	Battles	3	-	-	-	-	-	$0.00	$0.00	$0.00
83	Battles	4	-	-	-	-	-	$0.00	$0.00	$0.00
84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$1,191.36	$0.00	$168.81	$289.30
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	11/30/1999	$1,181.31	$1,191.36	$0.00	$168.81	$289.30
86	Battles	7	-	-	-	-	-	$0.00	$0.00	$0.00
87	Battles	8	-	-	-	-	-	$0.00	$0.00	$0.00
						SUM		$0.00	$1,012.86	$2,018.03

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Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	L	M	N	O	P
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	12/31/2001	12/31/2002	12/31/2003	12/31/2004	12/31/2005
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$0.00	$481.00	$206.13	$147.21	$105.13
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$0.00	$481.00	$206.13	$147.21	$105.13
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	7	1/13/2005	$11,688.02	$0.00	$0.00	$0.00	$0.00	$1,670.22
71	U-Cal	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
72	U-Cal	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	7	10/25/2005	$1,425.77	$0.00	$0.00	$0.00	$0.00	$203.74
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	7	2/12/2008	$2,711.88	$0.00	$0.00	$0.00	$0.00	$0.00
75	Escolle	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
76	Escolle	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
77	Escolle	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
78	Escolle	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	2/12/2008	$1,627.13	$0.00	$0.00	$0.00	$0.00	$0.00
80	Battles	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
81	Battles	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
82	Battles	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
83	Battles	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$206.61	$147.55	$105.49	$105.37	$105.49
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	11/30/1999	$1,181.31	$206.61	$147.55	$105.49	$105.37	$105.49
86	Battles	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
87	Battles	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
						SUM	$1,723.32	$11,812.70	$5,414.46	$4,047.24	$4,995.86

Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	Q	R	S	T	U
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$75.16	$75.08	$75.16	$37.54	$0.00
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$75.16	$75.08	$75.16	$37.54	$0.00
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	7	1/13/2005	$11,688.02	$2,862.40	$2,044.23	$1,459.83	$1,043.74	$1,042.57
71	U-Cal	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
72	U-Cal	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	7	10/25/2005	$1,425.77	$349.17	$249.37	$178.08	$127.32	$127.18
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	7	2/12/2008	$2,711.88	$0.00	$0.00	$1,549.70	$332.07	$237.15
75	Escolle	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
76	Escolle	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
77	Escolle	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
78	Escolle	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	2/12/2008	$1,627.13	$0.00	$0.00	$929.82	$199.24	$142.29
80	Battles	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
81	Battles	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
82	Battles	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
83	Battles	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$52.69	$0.00	$0.00	$0.00	$0.00
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	11/30/1999	$1,181.31	$52.69	$0.00	$0.00	$0.00	$0.00
86	Battles	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
87	Battles	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
						SUM	$5,357.62	$4,787.22	$7,062.88	$3,450.84	$2,208.05

Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	V	W	X	Y
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	12/31/2011	12/31/2012	12/31/2013	12/31/2014
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$0.00	$0.00	$0.00	$0.00
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$0.00	$0.00	$0.00	$0.00
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	7	1/13/2005	$11,688.02	$1,043.74	$521.29	$0.00	$0.00
71	U-Cal	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00
72	U-Cal	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	7	10/25/2005	$1,425.77	$127.32	$63.59	$0.00	$0.00
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	7	2/12/2008	$2,711.88	$169.36	$121.09	$120.95	$121.09
75	Escolle	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00
76	Escolle	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00
77	Escolle	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00
78	Escolle	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	2/12/2008	$1,627.13	$101.61	$72.65	$72.57	$72.65
80	Battles	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00
81	Battles	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00
82	Battles	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00
83	Battles	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00
84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$0.00	$0.00	$0.00	$0.00
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	11/30/1999	$1,181.31	$0.00	$0.00	$0.00	$0.00
86	Battles	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00
87	Battles	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00
						SUM	$1,913.10	$1,249.15	$664.58	$429.00

Appendix B: On-time – Capital Depreciation

A	B	C	D	E	F	G	Z	AA	AB
row	lease	Item #	Description	Depreciable life (years)	Initial date of non-compliance	Cost estimate as of non-compliance date	12/31/2015	12/31/2016	12/31/2017
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$0.00	$0.00	$0.00
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	8/31/2002	$1,202.41	$0.00	$0.00	$0.00
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	7	1/13/2005	$11,688.02	$0.00	$0.00	$0.00
71	U-Cal	7	-	-	-	-	$0.00	$0.00	$0.00
72	U-Cal	8	-	-	-	-	$0.00	$0.00	$0.00
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	7	10/25/2005	$1,425.77	$0.00	$0.00	$0.00
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	7	2/12/2008	$2,711.88	$60.47	$0.00	$0.00
75	Escolle	1	-	-	-	-	$0.00	$0.00	$0.00
76	Escolle	2	-	-	-	-	$0.00	$0.00	$0.00
77	Escolle	3	-	-	-	-	$0.00	$0.00	$0.00
78	Escolle	4	-	-	-	-	$0.00	$0.00	$0.00
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	2/12/2008	$1,627.13	$36.28	$0.00	$0.00
80	Battles	1	-	-	-	-	$0.00	$0.00	$0.00
81	Battles	2	-	-	-	-	$0.00	$0.00	$0.00
82	Battles	3	-	-	-	-	$0.00	$0.00	$0.00
83	Battles	4	-	-	-	-	$0.00	$0.00	$0.00
84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	11/30/1999	$1,181.31	$0.00	$0.00	$0.00
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	11/30/1999	$1,181.31	$0.00	$0.00	$0.00
86	Battles	7	-	-	-	-	$0.00	$0.00	$0.00
87	Battles	8	-	-	-	-	$0.00	$0.00	$0.00
						SUM	$96.76	$0.00	$0.00

Appendix B: On-time – Capital Depreciation

	Notes by column:
[A] - [H]	Reproduced from "On-time" table for capital costs only.
[I] - [AB]	Based on IRS depreciation schedules applicable for the on-time compliance year [F], depreciation in each year is reported. See "Depreciation" tab for more detail.
	All capital costs are assumed to have a 7 year recovery period (depreciated over 8 years). If applicable, the special depreciation allowance is taken in the first year, and the balance is depreciated according to MACRS guidelines (either accelerated or straight line depreciation under the General Depreciaton System as specified by IRS guidance).

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	H	I	J	K
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	NPV adjustment for year-end	12/31/1998	12/31/1999	12/31/2000
1	Williams B	1	-	-	-	-	-	$0.00	$0.00	$0.00
2	Williams B	2	-	-	-	-	-	$0.00	$0.00	$0.00
3	Williams B	3	-	-	-	-	-	$0.00	$0.00	$0.00
4	Williams B	4	-	-	-	-	-	$0.00	$0.00	$0.00
5	Williams B	5	The secondary containment around the tanks and production equipment was not present or were compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	3/19/2008	$2,759.11	$2,993.33	$0.00	$0.00	$0.00
6	Lloyd	1	-	-	-	-	-	$0.00	$0.00	$0.00
7	Lloyd	2	-	-	-	-	-	$0.00	$0.00	$0.00
8	Lloyd	3	-	-	-	-	-	$0.00	$0.00	$0.00
9	Lloyd	4	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/29/2007	$1,605.73	$1,677.34	$0.00	$0.00	$0.00
10	Lakeview	1	-	-	-	-	-	$0.00	$0.00	$0.00
11	Lakeview	2	-	-	-	-	-	$0.00	$0.00	$0.00
12	Lakeview	3	Two tanks were observed outside of secondary containment at the Lakeview facility.	7	6/29/2007	$2,676.21	$2,795.57	$0.00	$0.00	$0.00
13	Lakeview	4	-	-	-	-	-	$0.00	$0.00	$0.00
14	Lakeview	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/29/2007	$1,605.73	$1,677.34	$0.00	$0.00	$0.00
15	Los Flores	1	-	-	-	-	-	$0.00	$0.00	$0.00
16	Los Flores	2	-	-	-	-	-	$0.00	$0.00	$0.00
17	Los Flores	3	-	-	-	-	-	$0.00	$0.00	$0.00
18	Los Flores	4	-	-	-	-	-	$0.00	$0.00	$0.00
19	Los Flores	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/29/2007	$1,605.73	$1,677.34	$0.00	$0.00	$0.00
20	Los Flores	6	-	-	-	-	-	$0.00	$0.00	$0.00
21	Los Flores	7	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c)	7	6/20/2017	$1,659.62	$1,738.52	$0.00	$0.00	$0.00
22	Bell	1	-	-	-	-	-	$0.00	$0.00	$0.00
23	Bell	2	-	-	-	-	-	$0.00	$0.00	$0.00
24	Bell	3	-	-	-	-	-	$0.00	$0.00	$0.00
25	Bell	4a	-	-	-	-	-	$0.00	$0.00	$0.00
26	Bell	4b	-	-	-	-	-	$0.00	$0.00	$0.00

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Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	L	M	N	O	P
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2001	12/31/2002	12/31/2003	12/31/2004	12/31/2005
1	Williams B	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
2	Williams B	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
3	Williams B	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
4	Williams B	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
5	Williams B	5	The secondary containment around the tanks and production equipment was not present or were compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	3/19/2008	$2,759.11	$0.00	$0.00	$0.00	$0.00	$0.00
6	Lloyd	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
7	Lloyd	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
8	Lloyd	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
9	Lloyd	4	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/29/2007	$1,605.73	$0.00	$0.00	$0.00	$0.00	$0.00
10	Lakeview	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
11	Lakeview	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
12	Lakeview	3	Two tanks were observed outside of secondary containment at the Lakeview facility.	7	6/29/2007	$2,676.21	$0.00	$0.00	$0.00	$0.00	$0.00
13	Lakeview	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
14	Lakeview	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/29/2007	$1,605.73	$0.00	$0.00	$0.00	$0.00	$0.00
15	Los Flores	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
16	Los Flores	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
17	Los Flores	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
18	Los Flores	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
19	Los Flores	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/29/2007	$1,605.73	$0.00	$0.00	$0.00	$0.00	$0.00
20	Los Flores	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
21	Los Flores	7	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00	$0.00
22	Bell	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
23	Bell	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
24	Bell	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
25	Bell	4a	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
26	Bell	4b	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	Q	R	S	T	U
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010
1	Williams B	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
2	Williams B	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
3	Williams B	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
4	Williams B	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
5	Williams B	5	The secondary containment around the tanks and production equipment was not present or were compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	3/19/2008	$2,759.11	$0.00	$0.00	$1,576.69	$337.85	$241.28
6	Lloyd	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
7	Lloyd	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
8	Lloyd	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
9	Lloyd	4	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/29/2007	$1,605.73	$0.00	$229.46	$393.24	$280.84	$200.56
10	Lakeview	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
11	Lakeview	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
12	Lakeview	3	Two tanks were observed outside of secondary containment at the Lakeview facility.	7	6/29/2007	$2,676.21	$0.00	$382.43	$655.40	$468.07	$334.26
13	Lakeview	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
14	Lakeview	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/29/2007	$1,605.73	$0.00	$229.46	$393.24	$280.84	$200.56
15	Los Flores	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
16	Los Flores	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
17	Los Flores	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
18	Los Flores	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
19	Los Flores	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/29/2007	$1,605.73	$0.00	$229.46	$393.24	$280.84	$200.56
20	Los Flores	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
21	Los Flores	7	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00	$0.00
22	Bell	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
23	Bell	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
24	Bell	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
25	Bell	4a	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
26	Bell	4b	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	V	W	X	Y	Z
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015
1	Williams B	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
2	Williams B	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
3	Williams B	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
4	Williams B	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
5	Williams B	5	The secondary containment around the tanks and production equipment was not present or were compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	3/19/2008	$2,759.11	$172.31	$123.19	$123.06	$123.19	$61.53
6	Lloyd	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
7	Lloyd	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
8	Lloyd	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
9	Lloyd	4	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/29/2007	$1,605.73	$143.39	$143.23	$143.39	$71.62	$0.00
10	Lakeview	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
11	Lakeview	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
12	Lakeview	3	Two tanks were observed outside of secondary containment at the Lakeview facility.	7	6/29/2007	$2,676.21	$238.99	$238.72	$238.99	$119.36	$0.00
13	Lakeview	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
14	Lakeview	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/29/2007	$1,605.73	$143.39	$143.23	$143.39	$71.62	$0.00
15	Los Flores	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
16	Los Flores	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
17	Los Flores	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
18	Los Flores	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
19	Los Flores	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/29/2007	$1,605.73	$143.39	$143.23	$143.39	$71.62	$0.00
20	Los Flores	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
21	Los Flores	7	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00	$0.00
22	Bell	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
23	Bell	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
24	Bell	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
25	Bell	4a	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
26	Bell	4b	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	AA	AB	AC	AD	AE
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020
1	Williams B	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
2	Williams B	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
3	Williams B	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
4	Williams B	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
5	Williams B	5	The secondary containment around the tanks and production equipment was not present or were compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	3/19/2008	$2,759.11	$0.00	$0.00	$0.00	$0.00	$0.00
6	Lloyd	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
7	Lloyd	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
8	Lloyd	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
9	Lloyd	4	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/29/2007	$1,605.73	$0.00	$0.00	$0.00	$0.00	$0.00
10	Lakeview	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
11	Lakeview	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
12	Lakeview	3	Two tanks were observed outside of secondary containment at the Lakeview facility.	7	6/29/2007	$2,676.21	$0.00	$0.00	$0.00	$0.00	$0.00
13	Lakeview	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
14	Lakeview	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/29/2007	$1,605.73	$0.00	$0.00	$0.00	$0.00	$0.00
15	Los Flores	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
16	Los Flores	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
17	Los Flores	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
18	Los Flores	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
19	Los Flores	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/29/2007	$1,605.73	$0.00	$0.00	$0.00	$0.00	$0.00
20	Los Flores	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
21	Los Flores	7	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c)	7	6/20/2017	$1,659.62	$0.00	$948.39	$203.22	$145.13	$103.64
22	Bell	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
23	Bell	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
24	Bell	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
25	Bell	4a	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
26	Bell	4b	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	AF	AG	AH	AI	AJ
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
1	Williams B	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
2	Williams B	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
3	Williams B	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
4	Williams B	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
5	Williams B	5	The secondary containment around the tanks and production equipment was not present or were compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	3/19/2008	$2,759.11	$0.00	$0.00	$0.00	$0.00	$0.00
6	Lloyd	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
7	Lloyd	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
8	Lloyd	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
9	Lloyd	4	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/29/2007	$1,605.73	$0.00	$0.00	$0.00	$0.00	$0.00
10	Lakeview	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
11	Lakeview	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
12	Lakeview	3	Two tanks were observed outside of secondary containment at the Lakeview facility.	7	6/29/2007	$2,676.21	$0.00	$0.00	$0.00	$0.00	$0.00
13	Lakeview	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
14	Lakeview	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	6/29/2007	$1,605.73	$0.00	$0.00	$0.00	$0.00	$0.00
15	Los Flores	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
16	Los Flores	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
17	Los Flores	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
18	Los Flores	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
19	Los Flores	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/29/2007	$1,605.73	$0.00	$0.00	$0.00	$0.00	$0.00
20	Los Flores	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
21	Los Flores	7	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c)	7	6/20/2017	$1,659.62	$74.10	$74.02	$74.10	$37.01	$0.00
22	Bell	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
23	Bell	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
24	Bell	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
25	Bell	4a	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
26	Bell	4b	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	H	I	J	K
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	NPV adjustment for year-end	12/31/1998	12/31/1999	12/31/2000
27	Bell	4c	-	-	-	-	-	$0.00	$0.00	$0.00
28	Bell	4d	-	-	-	-	-	$0.00	$0.00	$0.00
29	Bell	4f	-	-	-	-	-	$0.00	$0.00	$0.00
30	Bell	4g	-	-	-	-	-	$0.00	$0.00	$0.00
31	Bell	4h	-	-	-	-	-	$0.00	$0.00	$0.00
32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$1,738.52	$0.00	$0.00	$0.00
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/29/2008	$1,627.13	$1,774.81	$0.00	$0.00	$0.00
34	Bell	7	-	-	-	-	-	$0.00	$0.00	$0.00
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	7	1/7/2008	$5,332.33	$5,904.47	$0.00	$0.00	$0.00
36	Chamberlin	1	-	-	-	-	-	$0.00	$0.00	$0.00
37	Chamberlin	2	-	-	-	-	-	$0.00	$0.00	$0.00
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$1,738.52	$0.00	$0.00	$0.00
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/5/2008	$1,627.13	$1,786.94	$0.00	$0.00	$0.00
40	Chamberlin	5	-	-	-	-	-	$0.00	$0.00	$0.00
41	Davis	1	-	-	-	-	-	$0.00	$0.00	$0.00
42	Davis	2	-	-	-	-	-	$0.00	$0.00	$0.00
43	Davis	3	-	-	-	-	-	$0.00	$0.00	$0.00
44	Davis	4	-	-	-	-	-	$0.00	$0.00	$0.00
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$1,738.52	$0.00	$0.00	$0.00

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Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	L	M	N
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2001	12/31/2002	12/31/2003
27	Bell	4c	-	-	-	-	$0.00	$0.00	$0.00
28	Bell	4d	-	-	-	-	$0.00	$0.00	$0.00
29	Bell	4f	-	-	-	-	$0.00	$0.00	$0.00
30	Bell	4g	-	-	-	-	$0.00	$0.00	$0.00
31	Bell	4h	-	-	-	-	$0.00	$0.00	$0.00
32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/29/2008	$1,627.13	$0.00	$0.00	$0.00
34	Bell	7	-	-	-	-	$0.00	$0.00	$0.00
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	7	1/7/2008	$5,332.33	$0.00	$0.00	$0.00
36	Chamberlin	1	-	-	-	-	$0.00	$0.00	$0.00
37	Chamberlin	2	-	-	-	-	$0.00	$0.00	$0.00
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/5/2008	$1,627.13	$0.00	$0.00	$0.00
40	Chamberlin	5	-	-	-	-	$0.00	$0.00	$0.00
41	Davis	1	-	-	-	-	$0.00	$0.00	$0.00
42	Davis	2	-	-	-	-	$0.00	$0.00	$0.00
43	Davis	3	-	-	-	-	$0.00	$0.00	$0.00
44	Davis	4	-	-	-	-	$0.00	$0.00	$0.00
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	O	P	Q	R
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2004	12/31/2005	12/31/2006	12/31/2007
27	Bell	4c	-	-	-	-	$0.00	$0.00	$0.00	$0.00
28	Bell	4d	-	-	-	-	$0.00	$0.00	$0.00	$0.00
29	Bell	4f	-	-	-	-	$0.00	$0.00	$0.00	$0.00
30	Bell	4g	-	-	-	-	$0.00	$0.00	$0.00	$0.00
31	Bell	4h	-	-	-	-	$0.00	$0.00	$0.00	$0.00
32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/29/2008	$1,627.13	$0.00	$0.00	$0.00	$0.00
34	Bell	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	7	1/7/2008	$5,332.33	$0.00	$0.00	$0.00	$0.00
36	Chamberlin	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00
37	Chamberlin	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/5/2008	$1,627.13	$0.00	$0.00	$0.00	$0.00
40	Chamberlin	5	-	-	-	-	$0.00	$0.00	$0.00	$0.00
41	Davis	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00
42	Davis	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00
43	Davis	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00
44	Davis	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	S	T	U	V
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2008	12/31/2009	12/31/2010	12/31/2011
27	Bell	4c	-	-	-	-	$0.00	$0.00	$0.00	$0.00
28	Bell	4d	-	-	-	-	$0.00	$0.00	$0.00	$0.00
29	Bell	4f	-	-	-	-	$0.00	$0.00	$0.00	$0.00
30	Bell	4g	-	-	-	-	$0.00	$0.00	$0.00	$0.00
31	Bell	4h	-	-	-	-	$0.00	$0.00	$0.00	$0.00
32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/29/2008	$1,627.13	$929.82	$199.24	$142.29	$101.61
34	Bell	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	7	1/7/2008	$5,332.33	$3,047.16	$652.94	$466.31	$333.00
36	Chamberlin	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00
37	Chamberlin	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/5/2008	$1,627.13	$929.82	$199.24	$142.29	$101.61
40	Chamberlin	5	-	-	-	-	$0.00	$0.00	$0.00	$0.00
41	Davis	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00
42	Davis	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00
43	Davis	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00
44	Davis	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	W	X	Y	Z
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2012	12/31/2013	12/31/2014	12/31/2015
27	Bell	4c	-	-	-	-	$0.00	$0.00	$0.00	$0.00
28	Bell	4d	-	-	-	-	$0.00	$0.00	$0.00	$0.00
29	Bell	4f	-	-	-	-	$0.00	$0.00	$0.00	$0.00
30	Bell	4g	-	-	-	-	$0.00	$0.00	$0.00	$0.00
31	Bell	4h	-	-	-	-	$0.00	$0.00	$0.00	$0.00
32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/29/2008	$1,627.13	$72.65	$72.57	$72.65	$36.28
34	Bell	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	7	1/7/2008	$5,332.33	$238.09	$237.82	$238.09	$118.91
36	Chamberlin	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00
37	Chamberlin	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/5/2008	$1,627.13	$72.65	$72.57	$72.65	$36.28
40	Chamberlin	5	-	-	-	-	$0.00	$0.00	$0.00	$0.00
41	Davis	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00
42	Davis	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00
43	Davis	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00
44	Davis	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	AA	AB	AC	AD
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2016	12/31/2017	12/31/2018	12/31/2019
27	Bell	4c	-	-	-	-	$0.00	$0.00	$0.00	$0.00
28	Bell	4d	-	-	-	-	$0.00	$0.00	$0.00	$0.00
29	Bell	4f	-	-	-	-	$0.00	$0.00	$0.00	$0.00
30	Bell	4g	-	-	-	-	$0.00	$0.00	$0.00	$0.00
31	Bell	4h	-	-	-	-	$0.00	$0.00	$0.00	$0.00
32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$948.39	$203.22	$145.13
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/29/2008	$1,627.13	$0.00	$0.00	$0.00	$0.00
34	Bell	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	7	1/7/2008	$5,332.33	$0.00	$0.00	$0.00	$0.00
36	Chamberlin	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00
37	Chamberlin	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$948.39	$203.22	$145.13
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/5/2008	$1,627.13	$0.00	$0.00	$0.00	$0.00
40	Chamberlin	5	-	-	-	-	$0.00	$0.00	$0.00	$0.00
41	Davis	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00
42	Davis	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00
43	Davis	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00
44	Davis	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$948.39	$203.22	$145.13

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	AE	AF	AG
row	**Lease**	**Item #**	**Description**	**Depreciable life (years)**	**Actual compliance date**	**Cost estimate as of actual compliance date**	**12/31/2020**	**12/31/2021**	**12/31/2022**
27	Bell	4c	-	-	-	-	$0.00	$0.00	$0.00
28	Bell	4d	-	-	-	-	$0.00	$0.00	$0.00
29	Bell	4f	-	-	-	-	$0.00	$0.00	$0.00
30	Bell	4g	-	-	-	-	$0.00	$0.00	$0.00
31	Bell	4h	-	-	-	-	$0.00	$0.00	$0.00
32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$103.64	$74.10	$74.02
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/29/2008	$1,627.13	$0.00	$0.00	$0.00
34	Bell	7	-	-	-	-	$0.00	$0.00	$0.00
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	7	1/7/2008	$5,332.33	$0.00	$0.00	$0.00
36	Chamberlin	1	-	-	-	-	$0.00	$0.00	$0.00
37	Chamberlin	2	-	-	-	-	$0.00	$0.00	$0.00
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$103.64	$74.10	$74.02
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/5/2008	$1,627.13	$0.00	$0.00	$0.00
40	Chamberlin	5	-	-	-	-	$0.00	$0.00	$0.00
41	Davis	1	-	-	-	-	$0.00	$0.00	$0.00
42	Davis	2	-	-	-	-	$0.00	$0.00	$0.00
43	Davis	3	-	-	-	-	$0.00	$0.00	$0.00
44	Davis	4	-	-	-	-	$0.00	$0.00	$0.00
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$103.64	$74.10	$74.02

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Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	AH	AI	AJ
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2023	12/31/2024	12/31/2025
27	Bell	4c	-	-	-	-	$0.00	$0.00	$0.00
28	Bell	4d	-	-	-	-	$0.00	$0.00	$0.00
29	Bell	4f	-	-	-	-	$0.00	$0.00	$0.00
30	Bell	4g	-	-	-	-	$0.00	$0.00	$0.00
31	Bell	4h	-	-	-	-	$0.00	$0.00	$0.00
32	Bell	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$74.10	$37.01	$0.00
33	Bell	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/19/07, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/29/2008	$1,627.13	$0.00	$0.00	$0.00
34	Bell	7	-	-	-	-	$0.00	$0.00	$0.00
35	Bell	8	Rain event caused the Blochman Ponds to overflow. Failure of secondary containment as well.	7	1/7/2008	$5,332.33	$0.00	$0.00	$0.00
36	Chamberlin	1	-	-	-	-	$0.00	$0.00	$0.00
37	Chamberlin	2	-	-	-	-	$0.00	$0.00	$0.00
38	Chamberlin	3	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$74.10	$37.01	$0.00
39	Chamberlin	4	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	2/5/2008	$1,627.13	$0.00	$0.00	$0.00
40	Chamberlin	5	-	-	-	-	$0.00	$0.00	$0.00
41	Davis	1	-	-	-	-	$0.00	$0.00	$0.00
42	Davis	2	-	-	-	-	$0.00	$0.00	$0.00
43	Davis	3	-	-	-	-	$0.00	$0.00	$0.00
44	Davis	4	-	-	-	-	$0.00	$0.00	$0.00
45	Davis	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$74.10	$37.01	$0.00

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Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	H	I	J	K
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	NPV adjustment for year-end	12/31/1998	12/31/1999	12/31/2000
46	Davis	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	5/30/2008	$1,760.06	$1,870.84	$0.00	$0.00	$0.00
47	Davis	7	-	-	-	-	-	$0.00	$0.00	$0.00
48	Davis	8	-	-	-	-	-	$0.00	$0.00	$0.00
49	Davis	9	-	-	-	-	-	$0.00	$0.00	$0.00
50	Casmalia	1	-	-	-	-	-	$0.00	$0.00	$0.00
51	Casmalia	2	-	-	-	-	-	$0.00	$0.00	$0.00
52	Casmalia	3	-	-	-	-	-	$0.00	$0.00	$0.00
53	Casmalia	4	-	-	-	-	-	$0.00	$0.00	$0.00
54	Casmalia	5	Secondary containment of the tank battery was compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	3/12/2008	$1,655.46	$1,799.57	$0.00	$0.00	$0.00
55	Casmalia	6	Secondary containment of the wastewater pond was observed to be in a poor condition. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	3/12/2008	$1,655.46	$1,799.57	$0.00	$0.00	$0.00
56	Casmalia	7	-	-	-	-	-	$0.00	$0.00	$0.00
57	Security	1	-	-	-	-	-	$0.00	$0.00	$0.00
58	Security	2	-	-	-	-	-	$0.00	$0.00	$0.00
59	Security	3	-	-	-	-	-	$0.00	$0.00	$0.00
60	Security	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires to provide appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$1,738.52	$0.00	$0.00	$0.00
61	Security	5	Greka stored kerosene distillate (KD) to increase the viscosity of the heavy crude produced at the Security Lease. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. (40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contained spill oil.)	7	6/20/2017	$13,830.13	$14,487.68	$0.00	$0.00	$0.00
62	Security	6	-	-	-	-	-	$0.00	$0.00	$0.00
63	Security	7	The secondary containment around the LCR tanks and Waste Oil Tank are compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. An inspection of the Pumper's Weekly Lease Inspection forms were reviewed and these items were not identified in any of the past inspections by the pumper dating back to 2005. (40 CFR 112.7c require appropriate containment and/or diversionary structures to prevent a discharge.)	7	3/12/2008	$1,655.46	$1,799.57	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	L	M	N	O	P
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2001	12/31/2002	12/31/2003	12/31/2004	12/31/2005
46	Davis	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	5/30/2008	$1,760.06	$0.00	$0.00	$0.00	$0.00	$0.00
47	Davis	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
48	Davis	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
49	Davis	9	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
50	Casmalia	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
51	Casmalia	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
52	Casmalia	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
53	Casmalia	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
54	Casmalia	5	Secondary containment of the tank battery was compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00	$0.00
55	Casmalia	6	Secondary containment of the wastewater pond was observed to be in a poor condition. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00	$0.00
56	Casmalia	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
57	Security	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
58	Security	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
59	Security	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
60	Security	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires to provide appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00	$0.00
61	Security	5	Greka stored kerosene distillate (KD) to increase the viscosity of the heavy crude produced at the Security Lease. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. (40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contained spill oil.)	7	6/20/2017	$13,830.13	$0.00	$0.00	$0.00	$0.00	$0.00
62	Security	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
63	Security	7	The secondary containment around the LCR tanks and Waste Oil Tank are compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. An inspection of the Pumper's Weekly Lease Inspection forms were reviewed and these items were not identified in any of the past inspections by the pumper dating back to 2005. (40 CFR 112.7c require appropriate containment and/or diversionary structures to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	Q	R	S	T	U
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010
46	Davis	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	5/30/2008	$1,760.06	$0.00	$0.00	$1,005.79	$215.52	$153.92
47	Davis	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
48	Davis	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
49	Davis	9	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
50	Casmalia	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
51	Casmalia	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
52	Casmalia	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
53	Casmalia	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
54	Casmalia	5	Secondary containment of the tank battery was compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$946.01	$202.71	$144.77
55	Casmalia	6	Secondary containment of the wastewater pond was observed to be in a poor condition. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$946.01	$202.71	$144.77
56	Casmalia	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
57	Security	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
58	Security	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
59	Security	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
60	Security	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires to provide appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00	$0.00
61	Security	5	Greka stored kerosene distillate (KD) to increase the viscosity of the heavy crude produced at the Security Lease. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. (40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contained spill oil.)	7	6/20/2017	$13,830.13	$0.00	$0.00	$0.00	$0.00	$0.00
62	Security	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
63	Security	7	The secondary containment around the LCR tanks and Waste Oil Tank are compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. An inspection of the Pumper's Weekly Lease Inspection forms were reviewed and these items were not identified in any of the past inspections by the pumper dating back to 2005. (40 CFR 112.7c require appropriate containment and/or diversionary structures to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$946.01	$202.71	$144.77

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	V	W	X	Y	Z
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015
46	Davis	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	5/30/2008	$1,760.06	$109.92	$78.59	$78.50	$78.59	$39.25
47	Davis	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
48	Davis	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
49	Davis	9	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
50	Casmalia	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
51	Casmalia	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
52	Casmalia	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
53	Casmalia	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
54	Casmalia	5	Secondary containment of the tank battery was compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	3/12/2008	$1,655.46	$103.38	$73.92	$73.83	$73.92	$36.92
55	Casmalia	6	Secondary containment of the wastewater pond was observed to be in a poor condition. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	3/12/2008	$1,655.46	$103.38	$73.92	$73.83	$73.92	$36.92
56	Casmalia	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
57	Security	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
58	Security	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
59	Security	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
60	Security	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires to provide appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00	$0.00
61	Security	5	Greka stored kerosene distillate (KD) to increase the viscosity of the heavy crude produced at the Security Lease. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. (40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contained spill oil.)	7	6/20/2017	$13,830.13	$0.00	$0.00	$0.00	$0.00	$0.00
62	Security	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
63	Security	7	The secondary containment around the LCR tanks and Waste Oil Tank are compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. An inspection of the Pumper's Weekly Lease Inspection forms were reviewed and these items were not identified in any of the past inspections by the pumper dating back to 2005. (40 CFR 112.7c require appropriate containment and/or diversionary structures to prevent a discharge.)	7	3/12/2008	$1,655.46	$103.38	$73.92	$73.83	$73.92	$36.92

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Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	AA	AB	AC	AD	AE
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020
46	Davis	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	5/30/2008	$1,760.06	$0.00	$0.00	$0.00	$0.00	$0.00
47	Davis	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
48	Davis	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
49	Davis	9	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
50	Casmalia	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
51	Casmalia	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
52	Casmalia	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
53	Casmalia	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
54	Casmalia	5	Secondary containment of the tank battery was compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00	$0.00
55	Casmalia	6	Secondary containment of the wastewater pond was observed to be in a poor condition. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00	$0.00
56	Casmalia	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
57	Security	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
58	Security	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
59	Security	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
60	Security	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires to provide appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$948.39	$203.22	$145.13	$103.64
61	Security	5	Greka stored kerosene distillate (KD) to increase the viscosity of the heavy crude produced at the Security Lease. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. (40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contained spill oil.)	7	6/20/2017	$13,830.13	$0.00	$7,903.23	$1,693.50	$1,209.45	$863.69
62	Security	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
63	Security	7	The secondary containment around the LCR tanks and Waste Oil Tank are compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. An inspection of the Pumper's Weekly Lease Inspection forms were reviewed and these items were not identified in any of the past inspections by the pumper dating back to 2005. (40 CFR 112.7c require appropriate containment and/or diversionary structures to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	AF	AG	AH	AI	AJ
row	**Lease**	**Item #**	**Description**	**Depreciable life (years)**	**Actual compliance date**	**Cost estimate as of actual compliance date**	**12/31/2021**	**12/31/2022**	**12/31/2023**	**12/31/2024**	**12/31/2025**
46	Davis	6	Secondary containment of the tank battery was compromised. During the SPCC inspection on 12/9/05, Greka was directed to inspect all containment berms and make necessary improvements. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	5/30/2008	$1,760.06	$0.00	$0.00	$0.00	$0.00	$0.00
47	Davis	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
48	Davis	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
49	Davis	9	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
50	Casmalia	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
51	Casmalia	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
52	Casmalia	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
53	Casmalia	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
54	Casmalia	5	Secondary containment of the tank battery was compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00	$0.00
55	Casmalia	6	Secondary containment of the wastewater pond was observed to be in a poor condition. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00	$0.00
56	Casmalia	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
57	Security	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
58	Security	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
59	Security	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
60	Security	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires to provide appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$74.10	$74.02	$74.10	$37.01	$0.00
61	Security	5	Greka stored kerosene distillate (KD) to increase the viscosity of the heavy crude produced at the Security Lease. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. (40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contained spill oil.)	7	6/20/2017	$13,830.13	$617.52	$616.82	$617.52	$308.41	$0.00
62	Security	6	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
63	Security	7	The secondary containment around the LCR tanks and Waste Oil Tank are compromised due to cracks, holes, erosion, and permeability of the secondary containment berms. An inspection of the Pumper's Weekly Lease Inspection forms were reviewed and these items were not identified in any of the past inspections by the pumper dating back to 2005. (40 CFR 112.7c require appropriate containment and/or diversionary structures to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	H	I	J
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	NPV adjustment for year-end	12/31/1998	12/31/1999
64	Security	8	-	-	-	-	-	$0.00	$0.00
65	U-Cal	1	-	-	-	-	-	$0.00	$0.00
66	U-Cal	2	-	-	-	-	-	$0.00	$0.00
67	U-Cal	3	-	-	-	-	-	$0.00	$0.00
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	7	N/A	$0.00	$0.00	$0.00	$0.00
71	U-Cal	7	-	-	-	-	-	$0.00	$0.00
72	U-Cal	8	-	-	-	-	-	$0.00	$0.00
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	7	N/A	$0.00	$0.00	$0.00	$0.00
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	7	N/A	$0.00	$0.00	$0.00	$0.00
75	Escolle	1	-	-	-	-	-	$0.00	$0.00
76	Escolle	2	-	-	-	-	-	$0.00	$0.00
77	Escolle	3	-	-	-	-	-	$0.00	$0.00
78	Escolle	4	-	-	-	-	-	$0.00	$0.00
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	3/12/2008	$1,655.46	$1,799.57	$0.00	$0.00
80	Battles	1	-	-	-	-	-	$0.00	$0.00
81	Battles	2	-	-	-	-	-	$0.00	$0.00
82	Battles	3	-	-	-	-	-	$0.00	$0.00

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Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	K	L	M	N
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2000	12/31/2001	12/31/2002	12/31/2003
64	Security	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00
65	U-Cal	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00
66	U-Cal	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00
67	U-Cal	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00
71	U-Cal	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00
72	U-Cal	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00
75	Escolle	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00
76	Escolle	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00
77	Escolle	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00
78	Escolle	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00
80	Battles	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00
81	Battles	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00
82	Battles	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00

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Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	O	P	Q
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2004	12/31/2005	12/31/2006
64	Security	8	-	-	-	-	$0.00	$0.00	$0.00
65	U-Cal	1	-	-	-	-	$0.00	$0.00	$0.00
66	U-Cal	2	-	-	-	-	$0.00	$0.00	$0.00
67	U-Cal	3	-	-	-	-	$0.00	$0.00	$0.00
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	7	N/A	$0.00	$0.00	$0.00	$0.00
71	U-Cal	7	-	-	-	-	$0.00	$0.00	$0.00
72	U-Cal	8	-	-	-	-	$0.00	$0.00	$0.00
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	7	N/A	$0.00	$0.00	$0.00	$0.00
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	7	N/A	$0.00	$0.00	$0.00	$0.00
75	Escolle	1	-	-	-	-	$0.00	$0.00	$0.00
76	Escolle	2	-	-	-	-	$0.00	$0.00	$0.00
77	Escolle	3	-	-	-	-	$0.00	$0.00	$0.00
78	Escolle	4	-	-	-	-	$0.00	$0.00	$0.00
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00
80	Battles	1	-	-	-	-	$0.00	$0.00	$0.00
81	Battles	2	-	-	-	-	$0.00	$0.00	$0.00
82	Battles	3	-	-	-	-	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	R	S	T
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2007	12/31/2008	12/31/2009
64	Security	8	-	-	-	-	$0.00	$0.00	$0.00
65	U-Cal	1	-	-	-	-	$0.00	$0.00	$0.00
66	U-Cal	2	-	-	-	-	$0.00	$0.00	$0.00
67	U-Cal	3	-	-	-	-	$0.00	$0.00	$0.00
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	7	N/A	$0.00	$0.00	$0.00	$0.00
71	U-Cal	7	-	-	-	-	$0.00	$0.00	$0.00
72	U-Cal	8	-	-	-	-	$0.00	$0.00	$0.00
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	7	N/A	$0.00	$0.00	$0.00	$0.00
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	7	N/A	$0.00	$0.00	$0.00	$0.00
75	Escolle	1	-	-	-	-	$0.00	$0.00	$0.00
76	Escolle	2	-	-	-	-	$0.00	$0.00	$0.00
77	Escolle	3	-	-	-	-	$0.00	$0.00	$0.00
78	Escolle	4	-	-	-	-	$0.00	$0.00	$0.00
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	3/12/2008	$1,655.46	$0.00	$946.01	$202.71
80	Battles	1	-	-	-	-	$0.00	$0.00	$0.00
81	Battles	2	-	-	-	-	$0.00	$0.00	$0.00
82	Battles	3	-	-	-	-	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	U	V	W
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2010	12/31/2011	12/31/2012
64	Security	8	-	-	-	-	$0.00	$0.00	$0.00
65	U-Cal	1	-	-	-	-	$0.00	$0.00	$0.00
66	U-Cal	2	-	-	-	-	$0.00	$0.00	$0.00
67	U-Cal	3	-	-	-	-	$0.00	$0.00	$0.00
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	7	N/A	$0.00	$0.00	$0.00	$0.00
71	U-Cal	7	-	-	-	-	$0.00	$0.00	$0.00
72	U-Cal	8	-	-	-	-	$0.00	$0.00	$0.00
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	7	N/A	$0.00	$0.00	$0.00	$0.00
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	7	N/A	$0.00	$0.00	$0.00	$0.00
75	Escolle	1	-	-	-	-	$0.00	$0.00	$0.00
76	Escolle	2	-	-	-	-	$0.00	$0.00	$0.00
77	Escolle	3	-	-	-	-	$0.00	$0.00	$0.00
78	Escolle	4	-	-	-	-	$0.00	$0.00	$0.00
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	3/12/2008	$1,655.46	$144.77	$103.38	$73.92
80	Battles	1	-	-	-	-	$0.00	$0.00	$0.00
81	Battles	2	-	-	-	-	$0.00	$0.00	$0.00
82	Battles	3	-	-	-	-	$0.00	$0.00	$0.00

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Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	X	Y	Z
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2013	12/31/2014	12/31/2015
64	Security	8	-	-	-	-	$0.00	$0.00	$0.00
65	U-Cal	1	-	-	-	-	$0.00	$0.00	$0.00
66	U-Cal	2	-	-	-	-	$0.00	$0.00	$0.00
67	U-Cal	3	-	-	-	-	$0.00	$0.00	$0.00
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	7	N/A	$0.00	$0.00	$0.00	$0.00
71	U-Cal	7	-	-	-	-	$0.00	$0.00	$0.00
72	U-Cal	8	-	-	-	-	$0.00	$0.00	$0.00
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	7	N/A	$0.00	$0.00	$0.00	$0.00
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	7	N/A	$0.00	$0.00	$0.00	$0.00
75	Escolle	1	-	-	-	-	$0.00	$0.00	$0.00
76	Escolle	2	-	-	-	-	$0.00	$0.00	$0.00
77	Escolle	3	-	-	-	-	$0.00	$0.00	$0.00
78	Escolle	4	-	-	-	-	$0.00	$0.00	$0.00
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	3/12/2008	$1,655.46	$73.83	$73.92	$36.92
80	Battles	1	-	-	-	-	$0.00	$0.00	$0.00
81	Battles	2	-	-	-	-	$0.00	$0.00	$0.00
82	Battles	3	-	-	-	-	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	AA	AB	AC	AD	AE
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020
64	Security	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
65	U-Cal	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
66	U-Cal	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
67	U-Cal	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
71	U-Cal	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
72	U-Cal	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
75	Escolle	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
76	Escolle	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
77	Escolle	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
78	Escolle	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00	$0.00
80	Battles	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
81	Battles	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
82	Battles	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	AF	AG	AH	AI	AJ
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
64	Security	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
65	U-Cal	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
66	U-Cal	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
67	U-Cal	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
68	U-Cal	4	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
69	U-Cal	5	Secondary containment of the tank battery was compromised at the Bradley 3 Island tank battery. (40 CFR 112.7d requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
70	U-Cal	6	Greka stored kerosene distillate (KD) to increase viscosity of the heavy crude produced at U-Cal. The KD is a light-end product that could permeate the earthen containment basin in the event of a release. 40 CFR 112.9(c)(1)(i) requires containment systems to be sufficiently impervious to contain spilled oil.	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
71	U-Cal	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
72	U-Cal	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
73	U-Cal	9	The secondary containment for the U-Cal tank battery was compromised.	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
74	U-Cal	10	A lube oil tank at the U-Cal Production Water Injection facility was observed without secondary containment. The bottom of lube oil tank was pitted and showing signs of poor integrity.	7	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
75	Escolle	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
76	Escolle	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
77	Escolle	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
78	Escolle	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
79	Escolle	5	The secondary containment around the tanks and production equipment was compromised due to cracks, holes, erosion, and permeability of the secondary containment berms, (40 CFR 112.7c).	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00	$0.00
80	Battles	1	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
81	Battles	2	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
82	Battles	3	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	H	I	J	K
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	NPV adjustment for year-end	12/31/1998	12/31/1999	12/31/2000
83	Battles	4	-	-	-	-	-	$0.00	$0.00	$0.00
84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$1,738.52	$0.00	$0.00	$0.00
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	3/12/2008	$1,655.46	$1,799.57	$0.00	$0.00	$0.00
86	Battles	7	-	-	-	-	-	$0.00	$0.00	$0.00
87	Battles	8	-	-	-	-	-	$0.00	$0.00	$0.00
						SUM		**$0.00**	**$0.00**	**$0.00**

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	L	M	N	O
row	**Lease**	**Item #**	**Description**	**Depreciable life (years)**	**Actual compliance date**	**Cost estimate as of actual compliance date**	**12/31/2001**	**12/31/2002**	**12/31/2003**	**12/31/2004**
83	Battles	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00
84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00
86	Battles	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00
87	Battles	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00
						SUM	**$0.00**	**$0.00**	**$0.00**	**$0.00**

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Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	P	Q	R	S
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2005	12/31/2006	12/31/2007	12/31/2008
83	Battles	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00
84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$946.01
86	Battles	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00
87	Battles	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00
						SUM	**$0.00**	**$0.00**	**$1,070.81**	**$14,054.49**

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	T	U	V	W
row	**Lease**	**Item #**	**Description**	**Depreciable life (years)**	**Actual compliance date**	**Cost estimate as of actual compliance date**	**12/31/2009**	**12/31/2010**	**12/31/2011**	**12/31/2012**
83	Battles	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00
84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	3/12/2008	$1,655.46	$202.71	$144.77	$103.38	$73.92
86	Battles	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00
87	Battles	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00
						SUM	**$3,928.95**	**$2,805.87**	**$2,004.53**	**$1,623.16**

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	X	Y	Z	AA
row	**Lease**	**Item #**	**Description**	**Depreciable life (years)**	**Actual compliance date**	**Cost estimate as of actual compliance date**	**12/31/2013**	**12/31/2014**	**12/31/2015**	**12/31/2016**
83	Battles	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00
84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$0.00	$0.00	$0.00	$0.00
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	3/12/2008	$1,655.46	$73.83	$73.92	$36.92	$0.00
86	Battles	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00
87	Battles	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00
						SUM	**$1,622.84**	**$1,288.96**	**$476.84**	**$0.00**

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Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	AB	AC	AD	AE
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2017	12/31/2018	12/31/2019	12/31/2020
83	Battles	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00
84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$948.39	$203.22	$145.13	$103.64
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00
86	Battles	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00
87	Battles	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00
						SUM	**$13,593.56**	**$2,912.82**	**$2,080.25**	**$1,485.55**

Appendix B: Actual – Capital Depreciation

A	B	C	D	E	F	G	AF	AG	AH	AI	AJ
row	Lease	Item #	Description	Depreciable life (years)	Actual compliance date	Cost estimate as of actual compliance date	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
83	Battles	4	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
84	Battles	5	No containment or diversionary at the truck loading/unloading rack. (40 CFR 112.7c requires appropriate containment and/or diversionary structures to prevent a discharge.)	7	6/20/2017	$1,659.62	$74.10	$74.02	$74.10	$37.01	$0.00
85	Battles	6	Secondary containment of tank battery compromised. (40 CFR 112.7c requires appropriate containment and/or diversionary structure to prevent a discharge.)	7	3/12/2008	$1,655.46	$0.00	$0.00	$0.00	$0.00	$0.00
86	Battles	7	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
87	Battles	8	-	-	-	-	$0.00	$0.00	$0.00	$0.00	$0.00
						SUM	$1,062.13	$1,060.94	$1,062.13	$530.47	$0.00

Notes by column:

[A] - [H] Reproduced from "Actual" table for capital costs only.

[I] - [AJ] Based on IRS depreciation schedules applicable for the actual compliance year [F], depreciation in each year is reported. Depreciation in future years is assumed to follow IRS guidelines for tax year 2015. See "Depreciation" tab for more detail.

All capital costs are assumed to have a 7 year recovery period (depreciated over 8 years). If applicable, the special depreciation allowance is taken in the first year, and the balance is depreciated according to MACRS guidelines (either accelerated or straight line depreciation under the General Depreciaton System as specified by IRS guidance).

Appendix B: On-time scenario

		12/31/1999	12/31/2000	12/31/2001	12/31/2002	12/31/2003	12/31/2004	12/31/2005
1	**Capital Costs**	$7,148.17	$2,087.10	$0.00	$27,415.97	$0.00	$0.00	$14,150.55
2	Depreciation	$1,012.86	$2,018.03	$1,723.32	$11,812.70	$5,414.46	$4,047.24	$4,995.86
3	Depreciation tax benefit	-$412.70	-$822.27	-$702.18	-$4,813.20	-$2,206.17	-$1,649.09	-$2,035.61
4	PV multiplier	5.42	4.91	4.39	3.97	3.57	3.25	2.98
5	PV as of penalty payment date	$36,504.19	$6,204.17	-$3,085.74	$89,694.67	-$7,866.63	-$5,354.90	$36,061.45
6								
7	**One-time costs**	$95,308.98	$20,870.95	$0.00	$165,378.52	$0.00	$0.00	$14,252.99
8	Tax benefit	-$38,834.60	-$8,504.08	$0.00	-$67,385.13	$0.00	$0.00	-$5,807.52
9	PV multiplier	5.42	4.91	4.39	3.97	3.57	3.25	2.98
10	PV as of penalty payment date	$306,073.68	$60,661.27	$0.00	$388,867.62	$0.00	$0.00	$25,138.87
11								
12	**Avoided recurring costs**	$395,730.81	$109,218.80	$14,771.97	$438,150.02	$21,543.36	$585,349.75	$24,937.18
13	Tax effect	-$161,244.48	-$44,502.29	-$6,018.99	-$178,528.61	-$8,778.06	-$238,506.61	-$10,160.90
14	PV multiplier	5.42	4.91	4.39	3.97	3.57	3.25	2.98
15	PV as of penalty payment date	$1,270,843.43	$317,443.63	$38,464.99	$1,030,256.83	$45,517.67	$1,126,263.68	$43,983.23
16								
17	**PV of total on-time costs**	$1,613,421.30	$384,309.07	$35,379.25	$1,508,819.11	$37,651.04	$1,120,908.78	$105,183.55
18	*PV as of NPV date*	*$6,727,210.58*						

	Notes by row:
1, 7	From "On-time" worksheet, column [L].
2	From "On-time - Capital Depreciation" worksheet, columns [I]-[AB].
3	Equal to negative of [row 2] * 40.75% (the company's combined tax rate).
4, 9, 14	From "Other inputs" worksheet.
5	Equal to ([row 1]+[row 3])*[row 4].
8	Equal to negative of [row 7] * 40.75% (the company's combined tax rate).
10	Equal to ([row 7]+[row 8]) * [row 9].
12	From "Avoided Recurring - PV Year End" worksheet, columns [I]-[AB]. These values represent avoided recurring costs. On-time, compliant costs not shown.
13	Equal to negative of [row 12] * 40.75% (the company's combined tax rate).
15	Equal to ([row 12] + [row 13]) * [row 14].
17	Equal to [row 5] + [row 10] + [row 15].
18	Equal to sum of values in row 17 for 1999-2025.

Appendix B: On-time scenario

		12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012
1	**Capital Costs**	$0.00	$5,305.00	$4,755.72	$0.00	$0.00	$0.00	$0.00
2	Depreciation	$5,357.62	$4,787.22	$7,062.88	$3,450.84	$2,208.05	$1,913.10	$1,249.15
3	Depreciation tax benefit	-$2,183.02	-$1,950.60	-$2,877.84	-$1,406.08	-$899.69	-$779.51	-$508.98
4	PV multiplier	2.73	2.48	2.28	2.05	1.82	1.63	1.47
5	PV as of penalty payment date	-$5,960.91	$8,329.07	$4,278.21	-$2,887.21	-$1,633.14	-$1,267.11	-$749.95
6								
7	**One-time costs**	$0.00	$3,487.01	$5,439.67	$3,471.70	$3,576.85	$0.00	$0.00
8	Tax benefit	$0.00	-$1,420.82	-$2,216.45	-$1,414.58	-$1,457.42	$0.00	$0.00
9	PV multiplier	2.73	2.48	2.28	2.05	1.82	1.63	1.47
10	PV as of penalty payment date	$0.00	$5,130.41	$7,343.19	$4,224.03	$3,847.22	$0.00	$0.00
11								
12	**Avoided recurring costs**	$153,243.61	$447,112.55	$184,591.10	$540,168.85	$20,908.22	$14,703.36	$14,314.26
13	Tax effect	-$62,440.64	-$182,180.48	-$75,213.49	-$220,097.20	-$8,519.26	-$5,991.03	-$5,832.49
14	PV multiplier	2.73	2.48	2.28	2.05	1.82	1.63	1.47
15	PV as of penalty payment date	$247,945.21	$657,833.51	$249,185.77	$657,225.96	$22,488.63	$14,162.04	$12,497.41
16								
17	**PV of total on-time costs**	$241,984.29	$671,292.99	$260,807.17	$658,562.78	$24,702.71	$12,894.94	$11,747.46
18	*PV as of NPV date*							

Appendix B: On-time scenario

		12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020
1	**Capital Costs**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	Depreciation	$664.58	$429.00	$96.76	$0.00	$0.00	$0.00	$0.00	$0.00
3	Depreciation tax benefit	-$270.79	-$174.80	-$39.43	$0.00	$0.00	$0.00	$0.00	$0.00
4	PV multiplier	1.35	1.24	1.13	1.04	0.95	0.86	0.78	0.71
5	PV as of penalty payment date	-$364.26	-$216.11	-$44.58	$0.00	$0.00	$0.00	$0.00	$0.00
6									
7	**One-time costs**	$0.00	$0.00	$0.00	$0.00	$0.00			
8	Tax benefit	$0.00	$0.00	$0.00	$0.00	$0.00			
9	PV multiplier	1.35	1.24	1.13	1.04	0.95			
10	PV as of penalty payment date	$0.00	$0.00	$0.00	$0.00	$0.00			
11									
12	**Avoided recurring costs**	$14,015.91	$14,334.41	$13,655.01	$13,438.13	$1,779.67			
13	Tax effect	-$5,710.92	-$5,840.70	-$5,563.87	-$5,475.50	-$725.14			
14	PV multiplier	1.35	1.24	1.13	1.04	1.00			
15	PV as of penalty payment date	$11,171.67	$10,501.11	$9,148.38	$8,295.40	$1,054.53			
16									
17	**PV of total on-time costs**	$10,807.41	$10,285.00	$9,103.81	$8,295.40	$1,054.53	$0.00	$0.00	$0.00
18	*PV as of NPV date*								

Appendix B: On-time scenario

		12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
1	**Capital Costs**	$0.00	$0.00	$0.00	$0.00	$0.00
2	Depreciation	$0.00	$0.00	$0.00	$0.00	$0.00
3	Depreciation tax benefit	$0.00	$0.00	$0.00	$0.00	$0.00
4	PV multiplier	0.65	0.59	0.53	0.48	0.44
5	PV as of penalty payment date	$0.00	$0.00	$0.00	$0.00	$0.00
6						
7	**One-time costs**					
8	Tax benefit					
9	PV multiplier					
10	PV as of penalty payment date					
11						
12	**Avoided recurring costs**					
13	Tax effect					
14	PV multiplier					
15	PV as of penalty payment date					
16						
17	**PV of total on-time costs**	$0.00	$0.00	$0.00	$0.00	$0.00
18	*PV as of NPV date*					

Appendix B: Actual scenario

		12/31/1999	12/31/2000	12/31/2001	12/31/2002	12/31/2003	12/31/2004	12/31/2005	12/31/2006
1	**Capital Costs**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	Depreciation	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	Depreciation tax benefit	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
4	PV multiplier	5.42	4.91	4.39	3.97	3.57	3.25	2.98	2.73
5	PV as of penalty payment date	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6									
7	**One-time costs**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
8	Tax benefit	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
9	PV multiplier	5.42	4.91	4.39	3.97	3.57	3.25	2.98	2.73
10	PV as of penalty payment date	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
11									
12	**Recurring costs**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
13	Tax effect	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
14	PV multiplier	5.42	4.91	4.39	3.97	3.57	3.25	2.98	2.73
15	PV as of penalty payment date	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
16									
17	**PV of total actual costs**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
18	*PV as of NPV date*	*$410,011.33*							

	Notes by row:
1, 7	From "Actual" worksheet, column [M].
2	From "Actual - Capital Depreciation" worksheet, columns [I]-[AJ].
3	Equal to negative of [row 2] * 40.75% (the company's combined tax rate).
4, 9, 14	From "Other inputs" worksheet.
5	Equal to ([row 1]+[row 3])*[row 4].
8	Equal to negative of [row 7] * 40.75% (the company's combined tax rate).
10	Equal to ([row 7]+[row 8]) * [row 9].
12	Equal to zero. Avoided recurring costs are shown on the "On-time scenario" worksheet.
13	Equal to negative of [row 12] * 40.75% (the company's combined tax rate).
15	Equal to ([row 12] + [row 13]) * [row 14].
17	Equal to [row 5] + [row 10] + [row 15].
18	Equal to sum of values in row 17 for 1999-2025.

Appendix B: Actual scenario

		12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014
1	**Capital Costs**	$7,827.59	$23,328.26	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	Depreciation	$1,070.81	$14,054.49	$3,928.95	$2,805.87	$2,004.53	$1,623.16	$1,622.84	$1,288.96
3	Depreciation tax benefit	-$436.31	-$5,726.64	-$1,600.89	-$1,143.28	-$816.77	-$661.37	-$661.24	-$525.20
4	PV multiplier	2.48	2.28	2.05	1.82	1.63	1.47	1.35	1.24
5	PV as of penalty payment date	$18,352.74	$40,100.28	-$3,287.22	-$2,075.30	-$1,327.67	-$974.50	-$889.49	-$649.33
6									
7	**One-time costs**	$13,331.16	$2,249.47	$0.00	$242,437.98	$62,630.27	$0.00	$0.00	$2,359.39
8	Tax benefit	-$5,431.91	-$916.57	$0.00	-$98,783.78	-$25,519.33	$0.00	$0.00	-$961.36
9	PV multiplier	2.48	2.28	2.05	1.82	1.63	1.47	1.35	1.24
10	PV as of penalty payment date	$19,614.04	$3,036.63	$0.00	$260,763.28	$60,324.47	$0.00	$0.00	$1,728.44
11									
12	**Recurring costs**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
13	Tax effect	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
14	PV multiplier	2.48	2.28	2.05	1.82	1.63	1.47	1.35	1.24
15	PV as of penalty payment date	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
16									
17	**PV of total actual costs**	$37,966.78	$43,136.91	-$3,287.22	$258,687.97	$58,996.80	-$974.50	-$889.49	$1,079.12
18	*PV as of NPV date*								

Appendix B: Actual scenario

		12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022
1	**Capital Costs**	$0.00	$0.00	$24,918.82	$0.00	$0.00	$0.00	$0.00	$0.00
2	Depreciation	$476.84	$0.00	$13,593.56	$2,912.82	$2,080.25	$1,485.55	$1,062.13	$1,060.94
3	Depreciation tax benefit	-$194.29	$0.00	-$5,538.83	-$1,186.86	-$847.62	-$605.30	-$432.77	-$432.29
4	PV multiplier	1.13	1.04	0.95	0.86	0.78	0.71	0.65	0.59
5	PV as of penalty payment date	-$219.68	$0.00	$18,500.39	-$1,023.75	-$663.85	-$430.44	-$279.43	-$253.44
6									
7	**One-time costs**	$0.00	$0.00	$0.00					
8	Tax benefit	$0.00	$0.00	$0.00					
9	PV multiplier	1.13	1.04	0.95					
10	PV as of penalty payment date	$0.00	$0.00	$0.00					
11									
12	**Recurring costs**	$0.00	$0.00	$0.00					
13	Tax effect	$0.00	$0.00	$0.00					
14	PV multiplier	1.13	1.04	1.00					
15	PV as of penalty payment date	$0.00	$0.00	$0.00					
16									
17	**PV of total actual costs**	-$219.68	$0.00	$18,500.39	-$1,023.75	-$663.85	-$430.44	-$279.43	-$253.44
18	*PV as of NPV date*								

Appendix B: Actual scenario

		12/31/2023	12/31/2024	12/31/2025
1	**Capital Costs**	$0.00	$0.00	$0.00
2	Depreciation	$1,062.13	$530.47	$0.00
3	Depreciation tax benefit	-$432.77	-$216.14	$0.00
4	PV multiplier	0.53	0.48	0.44
5	PV as of penalty payment date	-$230.37	-$104.47	$0.00
6				
7	**One-time costs**			
8	Tax benefit			
9	PV multiplier			
10	PV as of penalty payment date			
11				
12	**Recurring costs**			
13	Tax effect			
14	PV multiplier			
15	PV as of penalty payment date			
16				
17	**PV of total actual costs**	-$230.37	-$104.47	$0.00
18	*PV as of NPV date*			

1	Jan-98	388.0
2	Feb-98	388.0
3	Mar-98	386.8
4	Apr-98	386.7
5	May-98	387.0
6	Jun-98	386.6
7	Jul-98	389.3
8	Aug-98	391.1
9	Sep-98	390.0
10	Oct-98	391.5
11	Nov-98	390.5
12	Dec-98	390.4
13	Jan-99	389.0
14	Feb-99	387.9
15	Mar-99	388.8
16	Apr-99	388.6
17	May-99	389.9
18	Jun-99	390.4
19	Jul-99	391.9
20	Aug-99	392.1
21	Sep-99	392.7
22	Oct-99	392.0
23	Nov-99	391.9
24	Dec-99	392.0
25	Jan-00	391.1
26	Feb-00	391.1
27	Mar-00	392.4
28	Apr-00	393.4
29	May-00	394.5
30	Jun-00	393.1
31	Jul-00	393.7
32	Aug-00	394.7
33	Sep-00	396.3
34	Oct-00	397.0
35	Nov-00	395.7
36	Dec-00	395.8
37	Jan-01	395.4
38	Feb-01	395.1
39	Mar-01	394.2
40	Apr-01	394.5
41	May-01	395.4
42	Jun-01	395.0
43	Jul-01	395.3
44	Aug-01	396.3
45	Sep-01	394.3
46	Oct-01	392.6
47	Nov-01	392.3

48	Dec-01	390.5
49	Jan-02	390.2
50	Feb-02	389.4
51	Mar-02	391.5
52	Apr-02	392.5
53	May-02	392.8
54	Jun-02	396.4
55	Jul-02	397.7
56	Aug-02	398.9
57	Sep-02	401.0
58	Oct-02	400.0
59	Nov-02	398.7
60	Dec-02	398.1
61	Jan-03	397.2
62	Feb-03	397.2
63	Mar-03	398.4
64	Apr-03	400.0
65	May-03	401.3
66	Jun-03	400.0
67	Jul-03	401.3
68	Aug-03	402.4
69	Sep-03	404.0
70	Oct-03	405.9
71	Nov-03	407.2
72	Dec-03	409.0
73	Jan-04	411.0
74	Feb-04	418.6
75	Mar-04	426.3
76	Apr-04	437.9
77	May-04	442.5
78	Jun-04	442.6
79	Jul-04	445.6
80	Aug-04	457.2
81	Sep-04	459.7
82	Oct-04	462.4
83	Nov-04	462.5
84	Dec-04	464.5
85	Jan-05	465.3
86	Feb-05	468.2
87	Mar-05	468.3
88	Apr-05	467.6
89	May-05	468.3
90	Jun-05	466.3
91	Jul-05	461.9
92	Aug-05	461.6
93	Sep-05	467.2
94	Oct-05	473.0

Appendix B: PCI

95	Nov-05	473.9
96	Dec-05	476.4
97	Jan-06	478.6
98	Feb-06	480.7
99	Mar-06	482.2
100	Apr-06	486.7
101	May-06	495.6
102	Jun-06	502.6
103	Jul-06	509.1
104	Aug-06	510.0
105	Sep-06	513.0
106	Oct-06	515.5
107	Nov-06	511.4
108	Dec-06	509.2
109	Jan-07	509.7
110	Feb-07	512.4
111	Mar-07	517.7
112	Apr-07	529.2
113	May-07	531.8
114	Jun-07	532.7
115	Jul-07	533.7
116	Aug-07	531.5
117	Sep-07	528.2
118	Oct-07	527.1
119	Nov-07	526.0
120	Dec-07	525.0
121	Jan-08	530.7
122	Feb-08	539.8
123	Mar-08	549.2
124	Apr-08	560.9
125	May-08	583.9
126	Jun-08	597.1
127	Jul-08	608.8
128	Aug-08	619.3
129	Sep-08	608.9
130	Oct-08	592.2
131	Nov-08	566.2
132	Dec-08	548.3
133	Jan-09	539.6
134	Feb-09	532.3
135	Mar-09	522.6
136	Apr-09	511.7
137	May-09	509.1
138	Jun-09	512.0
139	Jul-09	512.1
140	Aug-09	521.9
141	Sep-09	525.7

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142	Oct-09	527.9
143	Nov-09	524.0
144	Dec-09	524.2
145	Jan-10	532.9
146	Feb-10	539.1
147	Mar-10	541.8
148	Apr-10	555.3
149	May-10	558.2
150	Jun-10	556.4
151	Jul-10	550.7
152	Aug-10	549.5
153	Sep-10	552.5
154	Oct-10	556.3
155	Nov-10	556.7
156	Dec-10	560.3
157	Jan-11	564.8
158	Feb-11	574.6
159	Mar-11	575.8
160	Apr-11	582.3
161	May-11	581.9
162	Jun-11	588.9
163	Jul-11	593.2
164	Aug-11	596.1
165	Sep-11	596.0
166	Oct-11	594.0
167	Nov-11	590.8
168	Dec-11	590.1
169	Jan-12	593.6
170	Feb-12	596.3
171	Mar-12	596.1
172	Apr-12	595.9
173	May-12	593.8
174	Jun-12	585.6
175	Jul-12	582.2
176	Aug-12	576.6
177	Sep-12	577.4
178	Oct-12	575.4
179	Nov-12	570.6
180	Dec-12	571.9
181	Jan-13	571.2
182	Feb-13	569.9
183	Mar-13	568.3
184	Apr-13	569.4
185	May-13	566.5
186	Jun-13	564.8
187	Jul-13	564.0
188	Aug-13	564.8

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189	Sep-13	567.3	
190	Oct-13	567.5	
191	Nov-13	566.6	
192	Dec-13	567.5	
193	Jan-14	572.8	
194	Feb-14	574.9	
195	Mar-14	571.5	
196	Apr-14	573.6	
197	May-14	574.3	
198	Jun-14	576.2	
199	Jul-14	576.9	
200	Aug-14	578.7	
201	Sep-14	580.1	
202	Oct-14	579.7	
203	Nov-14	578.4	
204	Dec-14	575.7	
205	Jan-15	573.1	
206	Feb-15	570.5	
207	Mar-15	568.6	
208	Apr-15	562.9	
209	May-15	560.5	
210	Jun-15	558.3	
211	Jul-15	556.3	
212	Aug-15	553.9	
213	Sep-15	550.3	
214	Oct-15	547.2	
215	Nov-15	542.8	
216	Dec-15	537.1	preliminary
217	Jan-16	*537.7*	
218	Feb-16	*538.3*	
219	Mar-16	*539.0*	
220	Apr-16	*539.6*	
221	May-16	*540.2*	
222	Jun-16	*540.8*	
223	Jul-16	*541.5*	
224	Aug-16	*542.1*	
225	Sep-16	*542.7*	
226	Oct-16	*543.4*	
227	Nov-16	*544.0*	
228	Dec-16	*544.6*	
229	Jan-17	*545.6*	
230	Feb-17	*546.6*	
231	Mar-17	*547.6*	
232	Apr-17	*548.6*	
233	May-17	*549.6*	
234	Jun-17	*550.6*	
235	Jul-17	*551.6*	

Inflation Forecasts (CPI-U)

	OMB	CBO	Average
2016	1.5%	1.3%	1.4%
2017	2.1%	2.3%	2.2%

Appendix B: PCI

236	Aug-17	*552.6*
237	Sep-17	*553.6*
238	Oct-17	*554.6*
239	Nov-17	*555.6*
240	Dec-17	*556.6*

Data from http://www.chemengonline.com/pci-home. December 2015 figure is preliminary. For January 2016 and beyond, index is extrapolated using the average forecasted CPI-based inflation rate from OMB and CBO for 2016 and 2017 (Office of Management and Budget, Analytical Perspectives, Economic Assumptions and Interactions with the Budget, Table 2-3, accessed October 31, 2016 at https://www.whitehouse.gov/sites/default/files/omb/budget/fy2017/assets/ap_2_assumptions.pdf.

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Appendix B: Depreciation

Period Beg.	Special Depreciation Allowance (GDS only)
1/1/1999	0
1/1/2000	0
1/1/2001	0
1/1/2002	30%
1/1/2003	30%
5/6/2003	30%
1/1/2004	50%
1/1/2005	0
1/1/2006	0
1/1/2007	0
1/1/2008	50%
1/1/2009	50%
1/1/2010	50%
9/9/2010	100%
1/1/2011	100%
1/1/2012	100%
1/1/2013	50%
1/1/2014	50%
1/1/2015	50%
1/1/2016	*50%*
1/1/2017	*50%*

Year	1	2	3	4	5	6	7	8
GDS 200% DB	14.29%	24.49%	17.49%	12.49%	8.93%	8.92%	8.93%	4.46%
GDS Straight Line	7.14%	14.29%	14.29%	14.28%	14.29%	14.28%	14.29%	7.14%

Notes and Sources:

All capital costs assumed to be depreciated under IRS MACRS guidelines, as described in IRS Publication 946, "How to Depreciate Property" (1999-2015) using the GDS recovery rate of 7 years for assets used in exploration for and production of petroleum and natural gas. In the first year of acquisition and use, any applicable special depreciation allowance specified by the IRS guidelines for the year is applied based on the full capital cost. The remaining balance is depreciated using the schedule in Table A-1 (General Depreciation System, 200% declining balance method, half-year basis) or A-8 (General Depreciation System, straight line method) of Publication 946. Note that assets with a 7 year GDS recovery period are depreciated over 8 tax years.

2016 and 2017 depreciation are assumed to follow the 2015 guidelines.

In its income tax returns from 2008-2014, Greka Integrated reported almost all of its depreciation deductions using the GDS 200% DB method, half-year basis.

Exhibit B:
Financial Condition
Expert Report

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EXPERT REPORT OF DR. JOAN K. MEYER

HVI Cat Canyon, Inc.'s Finances and Transactions with Related Entities

United States et al. v. HVI Cat Canyon, Inc., f/k/a Greka Oil & Gas, Inc.,
CV 11-05097 FMO (SSx) (C.D. Cal.)

Prepared for:
United States Department of Justice
Environment and Natural Resources Division
Environmental Enforcement Section

Signature Joan K. Meyer

Date Feb-9-2017

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I. SUMMARY OF OPINIONS

I have been retained by the U. S. Department of Justice, representing the Plaintiff, the United States of America ("United States"), to evaluate the financial condition of HVI Cat Canyon, Inc. ("HVI-CC"), as well as HVI-CC's historical transactions with affiliated entities. Based on my analysis, my expert opinions are as follows:

1. HVI-CC has not been managed as if it were a standalone business. Instead, it has been managed in concert with its affiliated entities. I have not seen anything to suggest this practice will change.
2. HVI-CC's financial condition has been weak for at least the past 10 years. The company recently negotiated a major debt restructuring that effectively eliminated nearly $100 million in liabilities from its balance sheet. Even so, HVI-CC recently has relied on funds from a related party to remain in operation. HVI-CC would not continue in business to this date without this support, all else being equal.
3. HVI-CC's affiliate, GLR, LLC, has been able and willing to lend funds that have allowed HVI-CC to continue in operation. I have not seen anything to suggest this practice will change.

I may revise my opinions based on new information.

II. BASIS FOR OPINION AND CURRICULUM VITAE

My opinions are based on my education and expertise in economic and financial analysis, experience with conducting financial analyses, independent research of certain publicly available information, and my review of documents produced in this litigation. My opinion is based on widely accepted financial and economic analysis principles.

My resume, testimony history for the last four years and compensation statement follow the main body of this report in **Appendix A**. The description of the information I considered in forming my opinions is contained in **Appendix B**.

III. HVI-CC HAS BEEN MANAGED IN CONCERT WITH ITS AFFILIATES

A. ORGANIZATION OF HVI-CC SUGGESTS IT IS PART OF A LARGER BUSINESS ENTITY

The organization of HVI-CC suggests it is part of a larger business entity. HVI-CC is part of the business holdings ultimately owned by Mr. Randeep S. Grewal. As shown in **Exhibit 1**, since early 2012, HVI-CC's direct parent is GOGH, LLC. Prior to that, HVI-CC's direct parent had been GIT, Inc. ("GIT").[1] GOGH, LLC is owned by GIT. GIT, in turn, is a holding company (meaning that it does not directly conduct operations but, instead, owns stock in subsidiaries that conduct business operations) headquartered in Santa Maria, California; Mr. Grewal serves as the CEO of GIT and HVI-CC.[2] In

[1] Greka Integrated, Inc. 2011 Federal Income Tax Returns, HVI064819 at HVI064829,

[2] Deposition of Randeep Grewal on October 12, 2016, pp. 37 and 259.

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addition to HVI-CC, GIT owns GRC, Inc. ("GRC", formerly named Santa Maria Refining Company), which operates an asphalt refinery in Santa Maria that is supplied, in part, by heavy crude oil produced by HVI-CC. GIT also owns GTL1, LLC, Greka Construction, LLC, and GInv, Inc. As of 2006, the principle asset base of the consolidated group of companies owned by GIT consisted of the oil and gas assets owed by HVI-CC.[3]

GIT is owned by GIN, LLC. At his deposition, Mr. Grewal was advised by his attorney not to provide the ownership information of GIN, LLC, but according to an undated organizational chart produced by HVI-CC, GIN, LLC is or was owned 50 percent each by Alexi Holdings Limited and Grewal Investments Limited.[4] I do not know what entity owns Alexi Holdings Limited or Grewal Investments Limited, but documents produced by HVI-CC identify Mr. Grewal as the ultimate sole beneficial shareholder of HVI-CC,[5] meaning he must be the sole beneficial shareholder of these entities as well.

In addition, I am aware of two other companies that are affiliated with HVI-CC: GLR, LLC ("GLR") and GHM, LLC ("GHM" formerly known as GHL, LLC and Grewal Holdings, LLC).[6] HVI-CC has not produced any corporate maps or other documents that show GLR or GHM's relationship to HVI-CC, and Mr. Grewal was advised not to answer by his attorney when questioned about the ownership of GLR.[7]

B. HVI-CC FREQUENTLY CONDUCTS TRANSACTIONS WITH AFFILIATES, MANY TO THE DETRIMENT OF HVI-CC

Since 2005, HVI-CC has entered into numerous transactions with affiliates, many of which have been to the detriment of HVI-CC. As explained below, HVI-CC's primary customer is an affiliate, it has lent substantial funds to affiliates in exchange for a promissory note that ultimately was canceled, lent to affiliates without charging interest, has borrowed from an affiliate at relatively high interest rates, has sold some of its oil and gas interests to an affiliate, pays a two percent overriding royalty to an affiliate, and recently transferred a 99.75 percent owned subsidiary to an affiliate.

Oil Sales to GRC

GRC is HVI-CC's primary customer. The oil and gas produced by HVI-CC's operations is mostly sold to GRC. In 2015, for example, HVI-CC received $28.2 million of its $30.7 million in total sales, or

[3] Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, pp. 28. Note that only the rough draft version of the transcript is available for review as of the date of my report. I reserve the right to update and revise my report as necessary when the final transcript becomes available.

[4] Organizational Chart, undated, Bates Number EPA9_0276083; Deposition of Randeep Grewal on October 12, 2016, p. 255.

[5] Amended and Restated Executive Employment Agreement, dated November 3, 1999, including amendments and assignments. HVI080000. Greka Integrated, Inc. Consolidated Financial Statements, Years Ended December 31, 2012 and 2011; HVI065364 at 382.

[6] Note that HVI-CC has affiliates named GRL, LLC and GLR, LLC. These are different entities despite similar names.

[7] Deposition of Randeep Grewal on October 12, 2016, pp. 268-9.

approximately 92 percent, from GRC.[8] Similarly, in 2014, HVI-CC received $50.3 million of its $60.4 million in sales from GRC. GRC has been HVI-CC's primary client since at least 2005.[9]

Assuming Affiliates' Debt in Exchange for Promissory Note Due in August 2015

On August 26, 2005, HVI-CC entered into two credit agreements totaling $150 million.[10] In the first of these, HVI-CC borrowed $95 million from a number of lenders for which Guggenheim Corporate Funding served as the administrative agent (hereinafter referred to as the "Guggenheim" loan).[11] The agreement was structured in two $47.5 million term loans referred to as "Term A" and "Term B". Both of the term loans were due in August 2009. The interest rate payable on the Term A loan was equal to the London Interbank Offered Rates ("LIBOR") plus 6.25 percent. Interest on the Term B loan was equal to LIBOR plus 9.75 percent. The Guggenheim credit agreement recognized that HVI-CC would use $79 million of the $95 million borrowed for the benefit of HVI-CC's affiliates, as follows: [12]

- $35 million would be used to pay GIT's pre-existing debt (GIT was then HVI-CC's direct parent);
- $30 million would be used to pay GRC's pre-existing debt (GRC, then Santa Maria Refining Company, was HVI-CC's sister company at the time and remains so today);
- $8 million would be provided in cash to GIT ($3 million for "Guggenheim interest escrow" and $5 million for "Holding company cash");
- $2 million would be provided in cash to GRC for "turnaround and upgrade"; and
- $4 million would be provided to "Grewal Holdings," abbreviated RSG.

In the second credit agreement, also signed on August 26, 2005, HVI-CC entered into a senior secured revolving loan with West LB due in August 2008 that allowed it to borrow up to $55 million at an interest rate of LIBOR plus 3.5 percent (hereinafter referred to as the "West LB" loan).[13]

Also on August 26, 2005, apparently in exchange for becoming the debtor on, and pledging substantially all of its assets to secure repayment of, the $79 million in repayment of debts owed by its corporate parent and affiliates, HVI-CC received a Promissory Note dated August 26, 2005 from GIT totaling $79

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[8] HVI Cat Canyon 2015 Audited Financial Statements, pages 6 and 13. HVI084242 and HVI084249.

[9] HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements Years Ended December 31, 2005. HVIFIN0002063.

[10] Credit Agreement dated August 26, 2005 between Greka Oil & Gas, Inc. and Guggenheim Corporate Funding, LLC, HVIFIN0001790 at HVIFIN0001790.

[11] Ibid.

[12] Credit Agreement dated August 26, 2005 between Greka Oil & Gas, Inc. and Guggenheim Corporate Funding, LLC, HVIFIN0001790 at HVIFIN0001790; See also, Schedule 6.01(n), Sources and Uses, HVIFIN0001882 at HVIFIN0001921. Note the fact that Grewal Holdings, LLC later changed its name to GHL, LLC and then GHM, LLC per Ex 1.

[13] I have not been furnished with the West LB credit agreement from 2005. However, it is referenced in Guggenheim Credit Agreement 2005 in Schedule 6.01(n). HVIFIN0001882 at HVIFIN0001921 and Greka Oil & Gas, Inc.'s 2006 Consolidated Financial Statements, HVI0002063 at HVIFIN0002078.

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million.[14] The principal amount owed on this Promissory Note accrued interest at an annual rate of 6.0 percent. Payments against this Promissory Note were to be made in the following manner:

> "On each estimated federal income tax payment date subsequent to the date hereof, Borrower [GIT] shall pay to the Lender [HVI-CC] an amount equal to the estimated federal income tax payment Lender [HVI-CC] would have been required to pay on such date if its estimated federal income tax were calculated on a separate company, standalone basis."[15]

Presumably, these payments from GIT were intended to compensate HVI-CC for the debt HVI-CC assumed in 2005 on behalf of its affiliates.[16]

My interpretation of the direct language of the Promissory Note is that GIT was to make annual payments to HVI-CC equal to the federal income tax payment HVI-CC would have owed had it paid federal taxes directly. By its terms, the Promissory Note called for annual payments to be made by GIT equal to the federal income tax HVI-CC would have paid had it filed its own federal tax returns. If HVI-CC had negative taxable income in any particular year, as calculated as a standalone company because of deductions and credits, for example, then no annual payment would have been due. The agreement additionally specifies that the calculation of the estimated federal income tax that HVI-CC would owe on a stand-alone basis was to be verified by HVI-CC's independent auditor.[17] I did not see any evidence that the auditor performed an annual calculation of the amount of federal tax HVI-CC would owe if it were a standalone company. This calculation was required under the direct language of the Promissory Note to determine how much GIT owed HVI-CC under the Promissory Note. HVI-CC's representative speculated that a tax provision was probably credited to the intercompany account to reflect HVI-CC's positive income in some years, but was not able to point to evidence to support this claim.[18]

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[14] Promissory Note from Greka Integrated, Inc. to Greka Oil & Gas, Inc. dated August 26, 2005. HVI066334 at HVI066336. Note that HVI-CC's 30(b)(6) witness testified that this note was the result of a debt refinance, although I believe he mistakenly states this debt refinance occurred in 2004. Credit Agreement dated August 26, 2005 between Greka Oil & Gas, Inc. and Guggenheim Corporate Funding, LLC, HVIFIN0001790 at HVIFIN0001790; See also, Schedule 6.01(n), Sources and Uses, HVIFIN0001882 at HVIFIN0001921. See Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, pp. 26-27.

[15] Promissory Note from Greka Integrated, Inc. to Greka Oil & Gas, Inc. dated August 26, 2005. HVI066334 at HVI066336.

[16] Note that HVI-CC's 30(b)(6) witness designated to testify about the Promissory Note testified that from a bookkeeping standpoint HVI-CC received the Promissory Note in exchange for assuming the $79 million in GIT debt onto their books at the time of the refinancing. Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, pp. 33-34

[17] Specifically, the Promissory Note states "The calculation of such estimated federal income tax payments and actual federal income tax payments determined on a separate company, stand alone basis shall be verified by Lender's [HVI-CC's] independent auditor." Promissory Note from Greka Integrated, Inc. to Greka Oil & Gas, Inc. dated August 26, 2005. HVI066334 at HVI066336.

[18] HVI-CC's 30(b)(6) witness speculated that the intercompany account was likely credited to reflect HVI-CC's positive income in some years, but did not have specific knowledge to state whether or how HVI-CC and GIT actually reduced the amounts owed under the Promissory Note in years when HVI-CC had positive income. The witness suggested that if such reductions occurred they would be reflected in accounting journals (See Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, pp. 38-42). To my knowledge no such accounting journals have been produced in this litigation.

Furthermore, the Promissory Note states that payments were to be made in "lawful money of the United States in immediately available funds" delivered to HVI-CC."[19] I interpret this language to mean that payments were to be made in cash. HVI-CC's auditor and 30(b)(6) witness testified that he did not believe HVI-CC necessarily expected to be repaid in cash nor would GIT have had adequate cash flow to repay this debt in case.[20]

The promissory note was originally scheduled to mature on August 1, 2015, stating "the principal balance of this Note, together with all accrued but unpaid interest shall be due and payable on August 1, 2015." I interpret this to mean that any principal and interest remaining at August 1, 2015 that had not already been paid through annual payments was to then be due from GIT to HVI-CC.

HVI-CC's audited financial statements support this interpretation. Each year from 2005 to 2012, the description of this debt in a note to the audited financial statements reads:

> "Certain amounts borrowed under the new finance agreement were used to pay off obligations to the Company's parent. Management considers the receivable to be collectible from the parent."[21]

I interpret this statement to mean that HVI-CC's management had assured the auditor that this promissory note would be paid in full by its due date. HVI's 30(b)(6) witness testified that HVI-CC expected to be repaid in some way, but not necessarily in cash.[22]

HVI-CC's 30(b)(6) witness, Mr. Johnson, testified that the company did not record the changing balance owed on the Promissory Note and did not accrue interest on the Promissory Note.[23] Overall, Mr. Johnson testified that HVI-CC did not treat this note as an outstanding loan from an accounting perspective.[24]

Modifications to Promissory Note Owed by GIT to HVI-CC Made it Uncollectable

On July 20, 2010, HVI-CC and GIT pushed the due date of the Promissory Note back fifteen years from August 2015 to August 2030.[25] HVI-CC's 30(b)(6) witness could not explain HVI-CC's motivation for agreeing to modify the Promissory Note in this way.[26]

On January 15, 2013, this Promissory Note was canceled and replaced by a Tax Sharing Agreement between HVI-CC and GIT that states:

> "Greka [GIT] previously issued to HVI that certain Promissory Note, dated August 26, 2005 … pursuant to which the Parties **intended** that Greka would be required to pay

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[19] Promissory Note from Greka Integrated, Inc. to Greka Oil & Gas, Inc. dated August 26, 2005. HVI066334 at HVI066336.

[20] Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, pp. 28, 32-33, 38.

[21] HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements Years Ended December 31, 2005-2012. HVIFIN0002063, HVI084312, HVI065327, and HVI065309.

[22] Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, pp. 28-33.

[23] Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, pp. 39-40, 42.

[24] Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, pp. 39-40.

[25] First Amendment to Note between Greka Integrated, Inc. and Greka Oil and Gas, Inc., HVI066334 at HVI066340.

[26] Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, pp. 44.

> amounts to HVI attributable to certain losses, deductions and credits of HVI that reduced the consolidated federal income tax liability of the Group. **The Parties [GIT and HVI] acknowledge and agree that the intent** of the Note and the Amendment was not to create an intercompany liability between Greka [GIT] and HVI, but rather to provide a method by which HVI would recoup the tax benefit of its losses, deductions and credits utilized by the Group."[27] [emphasis added]

This Tax Sharing Agreement was substantially different than the Promissory Note it replaced. Besides being titled "Promissory Note," the Promissory Note called for annual payments by GIT to HVI-CC equal to the federal income tax HVI-CC would have paid had it filed its own federal tax returns, as discussed above. Nowhere in the original 2005 or amended 2010 Promissory Note, is any tax benefit GIT may have gained from HVI-CC's losses, deductions and credits addressed.

The Tax Sharing Agreement provides that:

> "2. For each tax year, Greka [GIT] will pay to the Internal Revenue Service on HVI's behalf the amount of HVI's federal income tax liability, determined on a stand-alone basis (calculated without regard to any of HVI's losses, deductions or credits utilized by Greka [GIT]) up to the Tax Benefit Amount (as defined below). Greka's [GIT] obligation pursuant to the preceding sentence also will be satisfied to the extent that HVI's stand-alone federal income tax liability is reduced or eliminated by HVI's utilization of Greka's [GIT] losses, deductions or credits. The 'Tax Benefit Amount' shall equal the federal income tax liability that Greka [GIT] would have owed on a stand-alone basis but for its utilization of HVI's losses, deductions or credits."[28]

Under this Tax Sharing Agreement, instead of owing annual payments to HVI-CC, GIT receives credit for payments made to the IRS – payments that GIT was already responsible for as the company jointly filing federal income tax returns on behalf of itself and its subsidiaries.

Further, in calculating the annual "payment," any losses, deductions or credits that HVI-CC would have used to minimize its federal income taxes had it been a standalone company are explicitly excluded. As I understand it, as long as HVI-CC continues to suffer net losses on its income statement (as calculated on a tax basis), the company will receive no benefit from the Tax-Sharing Agreement that it would have received from IRS tax loss carryforward provisions if HVI-CC filed as a stand-alone company. Given that HVI-CC has generated very large net losses that it likely would have been able to carryforward to offset future taxable net income had it filed as a standalone company, this limitation is significant.

In addition to these disadvantages, the conversion of the Promissory Note to the Tax-Sharing Agreement was detrimental to HVI-CC and advantageous to GIT for several other reasons:

- The Tax Sharing Agreement caps GIT's obligation to HVI-CC at $79 million. Under the Promissory Notes, the total amount due on the maturity date of the loan equaled $79 million <u>plus</u> all interest accruing at six percent per year.

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[27] Letter agreement to Andrew deVegvar, President, HVI signed by Andrew deVegvar (President, HVI) and Randeep S. Grewal (Chairman & CEO, GIT), re: Tax Sharing Agreement, January 15, 2013, HVI066334.

[28] Ibid. at HVI066335.

- The Promissory Note had a maturity date by which all principal and interest needed to be paid from GIT to HVI-CC. The Tax Sharing Agreement has no maturity date.
- The Promissory Note accrued interest payable to HVI-CC while the Tax Sharing Agreement has no provisions for interest.
- The Promissory Note had "events of default," including GIT filing for bankruptcy and HVI-CC having to pay its own federal income taxes.[29] These events of default would have triggered all unpaid principal and interest to be immediately due to HVI-CC.[30] The Tax Sharing Agreement has no such provisions.
- The Tax Sharing Agreement added a new provision that it would be terminated if HVI-CC ceases to be a member of the affiliated group of companies. The Promissory Note had no such provision.

HVI-CC has never received any cash payments under either the Promissory Note or the Tax Sharing Agreement. When asked whether there was an expectation that HVI-CC would receive cash under the initial promissory note, Mr. Grewal testified, "No cash. HVI has always sucked cash and there's no cash owed to HVI."[31] Additionally, HVI-CC's Senior Vice President, Susan Whalen, testified that she does not believe HVI-CC ever received any cash from GIT under the canceled Promissory Note.[32] Under the terms of the Promissory Notes, HVI-CC should have received cash payments in 2005-2007 and 2009-2011 when it generated positive net income.[33]

As late as July 2010, HVI-CC held a note from GIT for $79 million plus interest due in 2015. As a result of the changes described above, HVI-CC now holds a tax-sharing asset that will not yield any benefit to HVI-CC unless HVI-CC becomes profitable on a taxable net income basis. These changes to the promissory note were detrimental to HVI-CC, and HVI-CC did not receive any benefit for these changes. The decision to first extend the maturity date of the Promissory Note from 2015 to 2030 does not appear to have been in HVI-CC's interest. In addition, the decision to replace the Promissory Note with the Tax Sharing Agreement clearly was detrimental to HVI-CC. Instead, these decisions appear to have been made by an entity or entities managing HVI-CC and GIT in concert with one another. These decisions led to HVI-CC incurring $79 million in debt that benefited HVI-CC's affiliates in exchange for a Promissory Note on which interest owed was ignored and required cash payments were not made. It then was replaced with a Tax Sharing Agreement under which cash payments would never be required.

[29] Tax Sharing Agreement between Greka Integrated, Inc. and Greka Oil & Gas, Inc.. Promissory Note dated August 25, 2005 page 3, HVI066334 at HVI066336-339

[30] Ibid.

[31] Deposition of Randeep Grewal on October 12, 2016, p. 281.

[32] Deposition of Susan Whalen on October 4, 2016, p. 61.

[33] Greka Oil & Gas, Inc. Consolidated Financial Statements, Years Ended December 31, 2005 to 2012, Bates Nos. HVIFIN0002063, HVI084312, HVI065327, HVI065309.Note that the net income reported in a company's audited financial statements differs from the net income calculated for tax purposes. HVI-CC's audited financial statements do not report the income taxes it would have paid had it been taxed on a standalone basis. In the absence of this information, I rely on the net income figures reported in HVI-CC' audited financial statements.

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HVI-CC's Interest-Free Loans to Affiliates

In 2006, HVI-CC provided $13,279,808 in advances to affiliates.[34] HVI-CC's representative testified that this was likely a cash advance to GIT.[35] It is unclear whether this transfer or transfers included any provision for interest. However, HVI-CC has not recorded any interest income on its income statements or statements of cash flows since at least 2005.[36] Therefore, it appears that HVI-CC failed to receive interest on these advances.

In 2007, HVI-CC entered into a Volumetric Production Payment (VPP) agreement in which it essentially forward-sold 4,824,573 barrels of oil yet to be extracted to UBS, a Swiss global financial services company, for $161.5 million.[37] From the $161.5 million in proceeds, $15 million was loaned to related-party GLR (Greka, LLC at the time).[38] This loan apparently was provided interest-free, as HVI-CC has not ever recorded any interest income on its income statements or statements of cash flows.[39]

HVI-CC's Borrowing from an Affiliate at Relatively High Interest Rates

GLR, LLC (formerly known as GLH, LLC) is an affiliate of HVI-CC.[40] GLR began to provide funds to HVI-CC through GIT beginning in 2008. Initially, loans from GLR were made to GIT through a 2008 Credit Agreement for $25 million that accrued interest at a rate of 12.5 percent per year.[41] Mr. Grewal testified that funds loaned to GIT from GLR were then loaned by GIT to HVI-CC.[42] As of December 31, 2012, HVI-CC owed approximately $38.1 million in principal and interest associated with this debt.[43] By

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[34] Greka Oil & Gas, Inc. Consolidated Financial Statements, Years Ended December 31, 2006 and 2005, HVIFIN0002063 at 2072.

[35] Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, p. 56.

[36] Greka Oil & Gas, Inc. Consolidated Financial Statements, Years Ended December 31, 2005 to 2015, Bates Nos. HVIFIN0002063, HVI084312, HVI065327, HVI065309, HVI076575, HVIFIN0000628, and HVI084234; HVIFIN0002063 at 2072.

[37] Greka Oil & Gas, Inc. Consolidated Financial Statements, Years Ended December 31, 2008 and 2007, HVI084312 at HVI084327; Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, p. 103.

[38] Schedule 2 to Purchase and Sale Agreement, Wire Transfers of Purchase Price. HVI084310 at311. GLR is described as a "related party" in HVI-CC's audited financial statements (see Greka Oil & Gas, Inc. Consolidated Financial Statements, Years Ended 2008 and 2007, HVI084312 at 321). HVI-CC has not produced any corporate maps or other documents that show GLR's relationship to HVI-CC, and Mr. Grewal was advised not to answer by his attorney when questioned about the ownership of GLR (see deposition of Randeep Grewal on October 12, 2016, p. 266).

[39] Consolidated financial statements of HVI-CC from 2005 to 2015. Bates Nos. HVIFIN0002063, HVI084312, HVI065327, HVI065309, HVI076575, HVIFIN0000628, and HVI084234.

[40] Second Lien Credit Agreement dated May 20, 2016 between HVI Cat Canyon, Inc. and UBS AG, HVI082519 at 592. Deposition of Randeep Grewal on October 12, 2016, p. 307.

[41] Credit Agreement dated June 1, 2008 between Greka Integrated, Inc. and Greka Land Holdings, LLC. HVIFIN0001333.

[42] Deposition of Randeep Grewal on October 12, 2016, p. 266.

[43] HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements for Years Ended December 31, 2012 and 2011, p. 12. HVI065309 at 323

December 31, 2015, this amount had increased to approximately $49.2 million including principal and interest.[44]

HVI-CC was charged interest rates by GLR of 12.5 percent while the 2008 Credit Agreement was active, but does not appear to have charged any interest on funds loaned to GLR or other affiliates. Between 2005 and 2007, HVI-CC's audited financial statements show that it advanced a total of $99,808,332 to its affiliates, yet HVI-CC has not recorded any income from interest on its income statement or statement of cash flows since 2005.[45] HVI-CC's representative stated that interest did not accrue on the Promissory Note between GIT and HVI-CC.[46]

Thus, HVI-CC borrowed from affiliates at relatively high interest rates of 12.5 percent per year while it charged no interest to affiliates. Such transactions are not in the financial or business interests of HVI-CC individually. The structure of these transactions is further evidence that HVI-CC is managed in concert with its affiliates, so the arrangement concerning interest ultimately is advantageous to an entity or entities managing HVI-CC and its affiliates jointly.

Oil Well Sold to Greka Refining Company

On at least one occasion, HVI-CC sold an oil well to its affiliate, GRC, Inc. (formerly known as Greka Refining Company and Santa Maria Refining Company). This sale does not appear to be the result of a business decision at HVI-CC to divest from this specific property and a business decision at GRC to begin to invest in oil and gas properties. Instead, I believe this decision likely was made by an entity or entities managing HVI-CC and GRC in concert with one another to provide liquidity to HVI-CC to pay its bills as they come due.

On November 9, 2015, HVI-CC's sole director, Randeep Grewal, retroactively authorized the officers to sell its right, title, and interest in the Union Sugar 34 well, effective October 30, 2015, to Greka Refining Company for $100,000 in cash, payable in five monthly installments of $20,000.[47] At the same meeting, the Director gave approval for HVI-CC to operate the well on behalf of Greka Refining Company for $2,480 per month.[48]

This transaction makes sense when viewed from the perspective that GRC and HVI-CC are managed in concert with each other. GRC is a company that owns and operates an asphalt refinery supplied, in part, by product purchased from HVI-CC. HVI-CC is a company that owns, produces, and manages oil and gas properties. From an operational standpoint, nothing changed with regard to the Union Sugar 34 well after the sale. HVI-CC is still operating the well and the resources from the property are still processed by GRC. While the sale benefited HVI-CC, it appears to have been merely a method to transfer funds to

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[44] HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements, Years Ended December 31, 2015 and 2014, p 13. HVI084249

[45] My estimate of the cash HVI-CC's transferred to affiliates from 2005 and 2007 is based on the "advance to affiliate" line item on HVI-CC's statement of cash flows for 2005-2007. Consolidated financial statements of HVI-CC from 2005 to 2015. Bates Nos. HVIFIN0002063, HVI084312, HVI065327, HVI065309, HVI076575, HVIFIN0000628, and HVI084234.

[46] Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, p, 41.

[47] Action by Unanimous Written Consent of the Sole Director of HVI Cat Canyon, Inc. on November 9, 2015. HVI084258

[48] Ibid.

HVI-CC from an affiliate to pay its bills as they come due, and is further evidence that HVI-CC is operated in concert with its affiliates rather than as a stand-alone entity.

Royalties Paid to Randeep Grewal

Mr. Grewal, the sole director and ultimate owner of HVI-CC, entered into an employment contract with GREKA Energy Corporation, on November 3, 1999.[49] On January 1, 2004, this employment agreement was assigned to GIT by GREKA Energy Corporation.[50] Under the agreement, Mr. Grewal (or a designee of his choosing):

> "… shall be entitled to receive an irrevocable, perpetual assignment of a two percent (2%) overriding royalty in all oil and gas interests wherever situated, now or hereafter, owned by the Company [GREKA Energy Corporation] or any of its direct and indirect subsidiaries, whether operated or non-operated by same."[51]

It appears that the designee that Mr. Grewal assigned his royalty interest from at least 2010 to November 2015 was Grewal (Royalty) LLC.[52] Over $7.8 million was paid from HVI-CC to Grewal (Royalty) LLC during this time.[53] In September 2014, the designee changed its name from Grewal (Royalty) LLC to GRL.[54] From September 2014 to November 2015, HVI-CC paid GRL $971,359.[55]

Therefore, whether HVI-CC is profitable or not, Mr. Grewal or his designee benefits as long as HVI-CC's oil and gas assets continue in active production.[56] For this reason, Mr. Grewal has an incentive to keep HVI-CC's oil and gas wells in operation even if HVI-CC is not a sustainable standalone business.

Transfer of Rincon Island Limited Partnership

Rincon Island Limited Partnership (Rincon) had been a subsidiary of HVI-CC from at least 2005 until August 8, 2016.[57] Rincon leased three oil and gas properties from The California State Lands

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[49] Amended and Restated Executive Employment Agreement dated November 3, 1999, HVI080000.

[50] Assignment and Assumption of Amended and Restated Executive Employment Agreement dated January 1, 2004. HVI08000 at HVI080023.

[51] Amendment No. 1 of Amended and Restated Executive Employment Agreement dated August 20, 2003. HVI080022.

[52] Greka Oil & Gas Revenue Accounting System Owner Payment History. January 2010 to September 2014. HVIFIN0001016; Deposition of Ernesto Olivares on October 3, 2016, p. 25.

[53] Greka Oil & Gas Revenue Accounting System Owner Payment History. January 2010 to September 2014. HVIFIN0001016

[54] Greka Oil & Gas Revenue Accounting System Owner Payment History. January 2010 to September 2014. HVIFIN0001016; Deposition of Susan Whalen on October 4, 2016, p. 51.

[55] Greka Oil & Gas Revenue Accounting System Owner Payment History. October 2010 to December 2014. HVIFIN0001016.

[56] Mr. Grewal testified that he is not the sole economic beneficiary interest holder of the entity that currently holds the overriding royalty interest (deposition p. 259). Thus, either GRL is no longer the entity that holds the overriding royalty interest or Mr. Grewal is not the sole economic beneficiary of GRL. I have not received any information regarding the consideration that Mr. Grewal may have directly held the overriding royalty interest or Mr. Grewal is not the sole economic beneficiary of GRL. I have not received any information regarding the consideration that Mr. Grewal may have directly or indirectly received as a result of the transaction that divested him of sole beneficial interest in the overriding royalty interest.

[57] Greka Oil and Gas and Subsidiary Consolidated Financial Statements, Years Ended December 31, 2006 and 2005, HVIFIN0002063 at HVIFIN0002073.

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Commission. Two of these properties are located onshore on private property and the third is located on an artificial oil and gas production island located 3,000 feet offshore.[58] HVI-CC was the 99.75 percent owner of Rincon as late as August 2016. HVI-CC was also the sole general partner of Rincon prior to 2016, with GOGH, LLC (HVI-CC's direct corporate parent) as a limited partner.[59]

On August 8, 2016, HVI-CC's sole board member, Mr. Grewal, transferred the ownership of Rincon to RILP-H, LLC ("RILP-H"), a newly-formed subsidiary of GOGH, LLC [60] RILP-H serves as the General Partner of Rincon as well as being the 99.75 percent owner.[61] Mr. Grewal is the sole member of RILP-H's Board of Managers.[62] Also on August 8, 2016, Rincon filed for Chapter 11 bankruptcy.[63] HVI-CC and GIT are named as creditors in this bankruptcy filing.[64]

It is unclear what motivated the transfer of Rincon from HVI-CC to the newly-formed RILP-H just before Rincon filed for bankruptcy protection. In a typical sale of a subsidiary that has value, the buyer pays the seller. However, given that Rincon's Chapter 11 petition shows assets that are worth far less than its liabilities, one might expect the owner (i.e., HVI-CC) to pay an unrelated buyer to take ownership of Rincon. Based on the information available for HVI-CC, however, it does not appear that any payments were received or paid by HVI-CC from RILP-H in connection with this transaction. As a result, this transfer appears to be another example of the fact that HVI-CC has not been managed as a standalone business.

Shared Employees

Susan Whalen is the Secretary, Senior Vice President and General Counsel of HVI-CC.[65] She also serves as the Secretary of RILP-H, LLC,[66] Secretary, Senior Vice President and General Counsel of GIT,[67] and

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[58] Statement by California State Lands Commission Re: Debtor's Emergency Motion for an Interim Order Authorizing Use of Cash Collateral and Approving Post-Petition Financing Pursuant to Section 364(c) and (d); and Declaration of Seth Blackmon, U.S. Bankruptcy Court, Northern District of Texas, Case 16-33174-hdh11, Doc 28, pages 1-3.

[59] Resolutions of the Board of Directors of HVI Cat Canyon, Inc., undated, but references documents from 2016. HVI084261.

[60] Resolutions of the Board of Directors of HVI Cat Canyon, Inc., August 8, 2016. HVI084279.

[61] Resolutions of the Board of Managers of RILP-H, LLC and Certificate of Resolutions, August 8, 2016, attached to the Voluntary Petition for Non-Individuals Filing for Bankruptcy submitted on August 8, 2016 by Rincon Island Limited Partnership, U.S. Bankruptcy Court, Northern District of Texas, Case 16-33174-hdh11, Doc 1, pages 6-9 of 9.

[62] Ibid., page 5 of 9.

[63] Voluntary Petition for Non-Individuals Filing for Bankruptcy. Filed by Rincon Greka Oil and Gas and Subsidiary Consolidated Financial Statements, Years Ended December 31, 2006 and 2005, HVIFIN0002063 at HVIFIN0002073.

[64] In the U.S. Bankruptcy Court for the Northern District of Texas, Dallas Division. Rincon Island Limited Partnership Chapter 11. Global Notes Regarding the Debtor's Schedules of Assets and Liabilities and Statement of Financial Affairs.

[65] Deposition of Susan Whalen on October 4, 2016p, p. 29. See, also, Minutes of Annual Meeting of Board of Directors of HVI Cat Canyon, Inc., June 9, 2015, HVIFIN0000952 at 953.

[66] Certificate of Resolutions, August 8, 2016, attached to the Voluntary Petition for Non-Individuals Filing for Bankruptcy submitted on August 8, 2016 by Rincon Island Limited Partnership, U.S. Bankruptcy Court, Northern District of Texas, Case 16-33174-hdh11, Doc 1, pages 8-9 of 9.

[67] Minutes of Annual Meeting of Board of Directors of Greka Integrated, Inc., June 9, 2015, HVIFIN0000893 at 894.

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Senior Vice President of GOGH.[68] Ms. Whalen testified that she had provided legal counsel to the following entities that are associated in some way with Mr. Grewal: Grevino, LLC; Ca' Del Grevino; GLR, LLC; GIN, LLC; GHM, LLC; GRL, LLC, and Mr. Grewal in his personal capacity.[69] She is paid by HVI-CC's parent, GIT, and does not track her time on work for other entities nor does she receive payment from any other entity for her work on behalf of Mr. Grewal and his affiliated businesses.[70] I have not seen any evidence that GIT has been reimbursed by any of these entities for Ms. Whalen's services.

Additionally, HVI-CC's Chief Financial Officer, Ernesto Olivares, is paid by GIT for his work at HVI-CC.[71] Mr. Olivares is also the Chief Financial Officer of GOGH, LLC and GIT.[72] He performs this role for all three companies but receives a single paycheck from GIT.[73]

Summary

The transactions with affiliates discussed above have had considerable impacts on HVI-CC's current financial condition, many of them detrimental. The Promissory Note entered into in 2005, for example, would have provided HVI-CC with $79 million plus interest in August 2015 if it had been repaid, were it not extended to 2030 and then replaced by the Tax-Sharing Agreement. Many of these transactions would not make financial sense if HVI-CC was managed as an independent company, but can be explained if HVI-CC is managed in concert with its affiliates.

Since I do not believe HVI-CC's finances are managed independently from its affiliates, it is not possible to meaningfully evaluate the company's financial condition independent from its affiliates. For example, HVI-CC would have been unable to meet its debt obligations without support from GLR since 2008. Furthermore, its debt obligations today would be far smaller if it never incurred debt on behalf of GIT in 2005, or if GIT had repaid this debt in 2015.

IV. HVI-CC WOULD NOT BE A VIABLE OPERATION AS A STANDALONE COMPANY

A. HVI-CC'S FINANCIAL CONDITION ON ITS OWN IS WEAK

Viewed in isolation, HVI-CC's financial condition has been weak for at least the past 10 years. During that time, the company has faced persistent problems in paying its debts as they come due. More recently, the company has been unable to achieve profitability on either an income or cash flow basis. Indeed, HVI-CC's auditor rendered a "going concern" opinion for the company in the most recent two years for which audited financial statements are available (i.e., 2014 and 2015).

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[68] Deposition of Susan Whalen on October 4, 2016, p. 35.

[69] Deposition of Susan Whalen on October 4, 2016, p. 27 and 34.

[70] Deposition of Susan Whalen on October 4, 2016, p. 34.

[71] Deposition of Ernesto Olivares on October 3, 2016, p. 18.

[72] Deposition of Ernesto Olivares on October 3, 2016, p. 19-21.

[73] Ibid.

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HVI-CC's Solvency Troubles

At least over the past 10 years, HVI-CC has faced solvency problems as evidenced by its inability to pay its debts as they come due. Most notably, HVI-CC faced persistent problems in meeting its obligations under the Volumetric Production Payment agreement (VPP) with UBS. Between May 2011 and July 2014, UBS sent HVI-CC at least 65 notifications of certain performance defaults.[74] By December 2015, HVI-CC owed UBS approximately $115.8 million in shortfall payments including accrued interest pursuant to the VPP.[75]

Furthermore, HVI-CC was unable to pay a large loan from GLR as it came due. HVI-CC owed approximately $49.2 million to GLR, due in December 2015. Instead of repaying the loan when due, HVI-CC refinanced the debt and issued another intercompany note to GLR with a principal amount up to $32.5 million in May 2016.[76] The interest due on the previous loan has remained on HVI-CC's balance sheet. As of September 30, 2016, HVI-CC owed a total of $61,644,244 in interest and principal to GLR.[77]

Finally, Mr. Grewal recently testified that HVI-CC is still experiencing difficulty paying bills as they come due. Mr. Grewal testified that HVI-CC "does not have enough cash flow to pay debt service" and that he is aware "that bills are not being paid."[78]

Another indication of HVI-CC's solvency problems is evident from HVI-CC's balance sheet, reproduced in **Exhibit 2.** The company's current liabilities (row 29; i.e., those liabilities that are due within the next 12 months) exceeded the value of HVI-CC's current assets (row 8; i.e., those assets that are either cash or assets that the company can reasonably be able to convert to cash within the next 12 months) in every year since 2008 and continuing through the third quarter of 2016. That means HVI-CC's debts due in the next 12 months exceed its assets that can be converted to cash within the next 12 months. This is a symptom that a company may not be able to meet its obligations over the next 12 months without generating enough cash flow to cover the potential shortfall from operations, investing, or additional financing.

Finally, HVI-CC was insolvent on a balance sheet basis in 2013 through 2015, as shown in **Exhibit 2**. To be insolvent on a balance sheet basis means that a company's total liabilities exceed its total assets, as booked on its balance sheet. At the end of 2015, for example, HVI-CC's liabilities totaled over $287 million (row 36), while its assets were booked as worth approximately $181.6 million (row 17). As of September 2016, however, HVI was solvent on a balance-sheet basis. As shown on **Exhibit 2**, HVI's assets totaled approximately $210 million (row 17), while its liabilities totaled approximately $190 million (row 36).

HVI's largest asset on its balance sheet as of December 2015 was its oil and gas properties. As of December 2015, these assets were valued at $111,921,660 (row 12). This is not the market value of the

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[74] Letter from UBS, AG to Greka Oil & Gas, Inc. dated July 28, 2014. Bates No. HVI080075.

[75] HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements Years Ended December 31, 2015 and 2014. HVI084234 at HVI084250.

[76] HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements Years Ended December 31, 2015 and 2014. HVI084234 at HVI084249 and HVI084252.

[77] HVI Cat Canyon, Inc. Balance Sheet at September 30, 2016 and 2015, HVI084287.

[78] Deposition of Randeep Grewal on October 12, 2016, p. 428.

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asset, however. Instead, this value reflects HVI's full-cost of acquisition, exploration, and development of its oil and gas reserves.[79] The unamortized cost of the oil & gas assets is limited to the sum of the estimated future net revenues from proved properties using the average price of oil over the past 12 months, discounted at ten percent.[80]

HVI-CC Has Been Unprofitable Since 2012

Over the recent past, HVI-CC has not been profitable on either an income or cash flow basis. As shown in HVI-CC's income statement (**Exhibit 3**), HVI-CC has not made a profit since 2012. Instead, between 2012 and the end of 2015, HVI-CC reported losses totaling approximately $89.4 million (row 15). These losses accelerated in more recent years, with HVI-CC losing nearly $37.1 million in 2015, alone. Through 2014, HVI-CC generated positive returns from its operations (row 6), but suffered losses due to its high cost of debt and VPP shortfalls (rows 8 and 9). In 2014, for example, the company had a positive income from operations of approximately $6.4 million (row 6), but had approximately $13.9 million in interest expenses (row 8) and approximately $21.0 million in VPP shortfalls (row 9). More recently, the decline in oil prices has led to HVI-CC suffering operating losses in addition to its high cost of debt. In 2015, HVI-CC lost approximately $9.4 million from its operations (row 6) and lost another approximately $27.6 million in debt expenses and VPP shortfalls (rows 8 and 9).

More recently, HVI-CC has not been generating positive cash flow from operating activities, which excludes loans and advances from affiliates and adjusts for non-cash items such as depreciation and changes in operating accounts. As shown on **Exhibit 4**, HVI-CC lost nearly $6.7 million in the first three months of 2016 from its operating activities (row 28).

HVI-CC's Auditor's Going Concern Opinion

HVI-CC's auditor, BDO USA, LLP, issued a "going concern" notice as part of the audit opinion in both 2014 and 2015.[81] This indicates significant doubt on the part of HVI-CC's auditor about HVI-CC's ability to continue as a viable business operation as of December 2014 or December 2015.[82]

HVI, in fact, did not face a forced liquidation in 2015 or 2016. The fact that the company restructured its debt in 2016 and received additional loans from its affiliates in 2016 appears to have helped HVI-CC avoid a forced liquidation. This restructuring is discussed below.

B. HVI-CC'S DEBT RESTRUCTURE IN 2016

In February 2007, HVI-CC entered into a Volumetric Production Payment (VPP) agreement with UBS. VPPs are structured so that, in return for an upfront cash payment by the VPP holder, the oil and gas producer commits to provide a specified volume of product to the VPP holder over a specified period of

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[79] HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements, Years Ended December 31, 2015 and 2014. HVI084234 at HVI084246.

[80] Ibid.

[81] HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements, Years Ended December 31, 2015 and 2014. HVI084234 at238.

[82] Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, pp. 155-160.

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time or until an aggregate total volume of the oil and gas has been delivered. VPPs allow the producers to monetize their oil and gas resources that are not yet developed while allowing them to retain full ownership of their assets without diluting their companies' equity. In this sense, VPPs allow producers to "sell ahead" or "forward sell" future production. Under the VPP, HVI-CC agreed to supply approximately 4.8 million barrels of its proven, but unproduced, reserves to UBS in exchange for $161.5 million.[83]

In concert with the VPP agreement, HVI-CC additionally entered into a Production and Market Agreement with UBS.[84] Under the Production and Market agreement, HVI-CC agreed to buy back all of the hydrocarbons it produced for UBS under the VPP contract on a monthly basis. Further, the Production and Market Agreement recognized that, once repurchased, HVI-CC could then either sell the hydrocarbons on the open market or to its affiliate, GRC for use at GRC's asphalt refinery.

As discussed above, HVI-CC experienced problems in meeting its production payment requirements under the original 2007 VPP agreement. According to HVI-CC's auditor and 30(B)(6) witness, HVI-CC was in default on its VPP requirements almost from the day the agreement was signed.[85] In 2010, UBS and HVI-CC entered into a new agreement that increased the total number of barrels due, extended the delivery schedule from 2014 to 2022, resolved HVI-CC's monetary shortfall obligations that had accrued since 2007, and included financial covenants requiring HVI-CC to maintain minimum cash balances and to restrict dividends or other distributions to shareholder.[86] HVI-CC's audited financials for 2011-2014, however, show that in each of these years, HVI-CC failed to make all of the required payments.[87]

In May 2016, HVI-CC implemented a major debt restructuring that effectively removed nearly $100 million in total liabilities from its balance sheet. It did so by entering into two new loans of $50 million each with UBS. The proceeds were used to extinguish the VPP agreement between UBS and HVI-CC, under which HVI-CC owed UBS back payments and oil to be extracted totaling nearly $200 million.[88] The first $50 million credit agreement accrues interest at the LIBOR rate plus 3.5 percent and matures on June 30, 2021.[89] The second $50 million credit agreement is due on December 31, 2021 and accrues interest at 6.0 percent per year.[90] The second agreement is also subject to performance payments and adjustments to the final settlement amount based on the price of crude oil.[91]

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[83] Greka Oil & Gas, Inc. Consolidated Financial Statements, Years Ended December 31, 2008 and 2007, HVI084312 at HVI084327

[84] Production and Marketing Agreement between Greka Oil & Gas, Inc. and UBS AG, dated February 14, 2007. HVI065574.

[85] Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, p. 160.

[86] Greka Oil & Gas, Inc. Consolidated Financial Statements for Years Ended December 31, 2010 and 2009, HVI065327 at 342.

[87] Greka Oil & Gas, Inc. Consolidated Financial Statements for Years Ended December 31, 2011 to 2014. Bates Nos. HVI065309, HVI076575, and HVIFIN0000628.

[88] Deposition of Randeep Grewal on October 12, 2016, pp. 297-303; First Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016. HVI082276

[89] First Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016. HVI082276 at, HVI082324-6, HVI082324, and HVI082311

[90] Second Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016, HVI082519 at HVI082563-4

[91] Second Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016, Bates No. HVI082519 HVI082542; HVI082548; HVI082568

Both of the credit agreements have very specific negative covenants. They prohibit HVI-CC from directly or indirectly causing further indebtedness, liens, and leaseback transactions.[92] They also prohibit HVI-CC from selling oil to GRC for less than a minimum market price.[93] The second agreement also includes quarterly performance payments if West Text Intermediate crude oil ("WTI") is over $65 per barrel for a quarter and a final settlement amount if WTI averages above $60 for the lifetime of the agreement.[94]

The result of this restructuring is shown in the final column of **Exhibit 2**, which reflects HVI-CC's balance sheet as of September 30, 2016. While the company's total assets (row 17) now exceed its total liabilities (row 36) by approximately $20 million (row 41), its current liabilities (row 29) still outweigh its current assets (row 8) by a wide margin. The company still has approximately $22.9 million in current liabilities (row 29) compared to just over $1.0 million in current assets (row 8).

As explained in the next section, the most recent financial information available shows that HVI-CC does not presently generate a positive cash flow from its oil and gas operations. Therefore, if HVI-CC was operated as a standalone entity, I would expect that it would not be able to meet its obligations as they come due over the next 12 months unless it sells assets, takes on additional debt, restructures its operations to significantly reduce its costs and expenses, and/or the market price for its products increases significantly. Recently, it has failed to generate positive cash flow from operations and it does not have liquid assets to pay its obligations that will come due over the next 12 months. In the past, HVI-CC has met its cash flow difficulties by actions such as failing to deliver the proceeds from product pledged to UBS under the VPP agreement (and selling the product, itself, instead), delaying and avoiding payments to creditors and vendors, selling oil and gas assets, and borrowing from GLR.

Furthermore, as shown in **Exhibit 3,** in the first three quarters of 2016, HVI-CC lost $6.0 million in operating income (row 6) while incurring approximately $7.3 million in interest expenses (row 8). In the third quarter alone -- the only quarter following the debt restructuring for which I have seen financial results -- HVI-CC lost over $1.5 million in operating income (row 6). HVI-CC does not appear to have any obvious solutions to its current financial predicament other than borrowing from affiliates. HVI-CC's auditor and 30(b)(6) witness testified that as early as 2008, no other entities except related parties would put money into HVI-CC.[95] Since HVI-CC continues to have short-term debts that outweigh its liquid assets and remains unprofitable, I believe the company would not be viable without support from its affiliated entities. Additionally, as described in the section below, I believe that HVI-CC would not have been viable over the past several years without ongoing financial support from GLR.

V. HVI-CC RECEIVED FUNDING FROM ITS AFFILIATE, GLR

Since HVI-CC would not be a viable operation as a standalone entity, it has relied on loans from an affiliate, GLR. The company would have difficulty obtaining funds from an unrelated lender due to its poor financial condition and because its existing credit agreements with UBS restrict its ability to take on

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[92] First Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016. HVI082276 at, HVI082369-70

[93] Ibid.

[94] Second Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016. HVI082496 at HVI082542 and HVI082552.

[95] Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, pp. 101-103.

additional debt.[96] Since 2008, HVI-CC has received financial support from an affiliate, GLR. As explained below, GLR has loaned funds to GIT that GIT, in turn, has then loaned to HVI-CC.

A. 2008 CREDIT AGREEMENT WITH GLR

GLR, LLC (formerly known as GLH LLC; Greka Land Holdings, LLC; Greka, LLC: and Grewal Finance, LLC) is an affiliate of HVI-CC.[97] GLR began to provide funds to HVI-CC through GIT beginning in 2008. Initially, loans from GLR were made to GIT through a 2008 Credit Agreement for $25 million that accrued interest at a rate of 12.5 percent per year.[98] Mr. Grewal testified that funds loaned to GIT from GLR were then loaned to HVI-CC.[99] As of December 31, 2012, HVI-CC owed approximately $38.1 million in principal and interest associated with this debt.[100] By December 31, 2015, this amount had increased to approximately $49.2 million including principal and interest.[101]

HVI-CC was charged interest rates by GLR of 12.5 percent while the 2008 Credit Agreement was active, but HVI-CC does not appear to have charged any interest on funds loaned to GLR or other affiliates. Between 2005 and 2007, HVI-CC advanced a total of $99,808,332 in cash to its affiliates, yet HVI-CC has not recorded any income from interest on its income statement or statement of cash flows since 2005.[102] These transactions are not in the financial or business interest of HVI-CC, individually. Instead, this structure provides evidence to support that HVI-CC in managed in concert with its affiliates.

B. 2016 DEBT RESTRUCTURING AND FURTHER LOANS

In 2016, GIT and GLR appear to have restructured their debt agreement, though I have not seen the revised agreement itself. Mr. Grewal testified that this new debt agreement works similarly to the previous 2008 Credit Agreement between GLR and GIT, and that GLR is currently a creditor to HVI-CC through GIT.[103] GLR provides loans to GIT and those funds are then loaned to HVI-CC. [104] These loans have a maturity date and an interest rate, but Mr. Grewal could not recall these terms at the time of his

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[96] First Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016. HVI082276 at, HVI082369-70; Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017, p. 103.

[97] Second Lien Credit Agreement between HVI Cat Canyon, Inc. and UBS AG dated May 20, 2016. HVI082496 at HVI082592. Deposition of Deposition of Randeep Grewal on October 12, 2016, p. 307. Note that Mr. Grewal confirms that "Transactions with Affiliates" refers to the GLR Facility.

[98] Credit Agreement dated June 1, 2008 between Greka Integrated, Inc. and Greka Land Holdings, LLC

[99] Deposition of Randeep Grewal on October 12, 2016, p. 266; Deposition of Susan Whalen on October 4, 2016, pp. 89-91.

[100] HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements for Years Ended December 31, 2012 and 2011, p. 12. HVI065309 at 323.

[101] HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements, Years Ended December 31, 2015 and 2014, p 13. HVI084249

[102] My estimate of HVI-CC's amount sent to affiliates from 2005 and 2007 is based on the "advance to affiliate" line item on HVI-CC's statement of cash flows for 2005-2007. Consolidated financial statements of HVI-CC from 2005 to 2015. Bates Nos. HVIFIN0002063, HVI084312, HVI065327, HVI065309, HVI076575, HVIFIN0000628, and HVI084234.

[103] Deposition of Randeep Grewal on October 12, 2016, p. 266.

[104] Ibid.

deposition.[105] Mr. Grewal testified that HVI-CC can repay these funds to GLR directly rather than repaying GIT.[106]

In addition, Mr. Grewal testified that HVI-CC has borrowed additional funds in 2016 through this restructured agreement between GIT and GLR. In 2016, HVI-CC spent between $3 million and $7.5 million of funds borrowed from GLR in order to cover its operating losses.[107]

C. 2016 LOANS TO RINCON ISLAND LIMITED PARTNERSHIP

In 2016, GLR also provided up to $10 million to Rincon for debtor-in-possession financing during its bankruptcy.[108] GIT was originally the creditor to supply this $10 million financing, but Rincon changed the lender to GLR two weeks later because UBS objected to GIT's role as the lender.[109]

Overall GLR has provided over $40 million in loans to HVI-CC and Rincon Island Limited Partnership since 2008. I have not seen evidence suggesting that GLR will not continue to make loans to HVI-CC and its affiliates as needed to cover expenses as they come due.

VI. CONCLUSION

Based on my analysis, my expert opinions are as follows:

1. HVI-CC has not been managed as if it were a standalone business. Instead, it has been managed in concert with its affiliated entities. I have not seen anything to suggest this practice will change.
2. HVI-CC's financial condition has been weak for at least the past 10 years. The company recently negotiated a major debt restructuring that effectively eliminated nearly $100 million in liabilities from its balance sheet. Even so, HVI-CC recently has relied on funds from a related party to remain in operation. HVI-CC would not continue in business to this date without this support, all else being equal.
3. HVI-CC's affiliate, GLR, LLC, has been able and willing to lend funds that have allowed HVI-CC to continue in operation. I have not seen anything to suggest this practice will change.

I may revise my opinions based on new information.

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[105] Deposition of Randeep Grewal on October 12, 2016, p. 267.

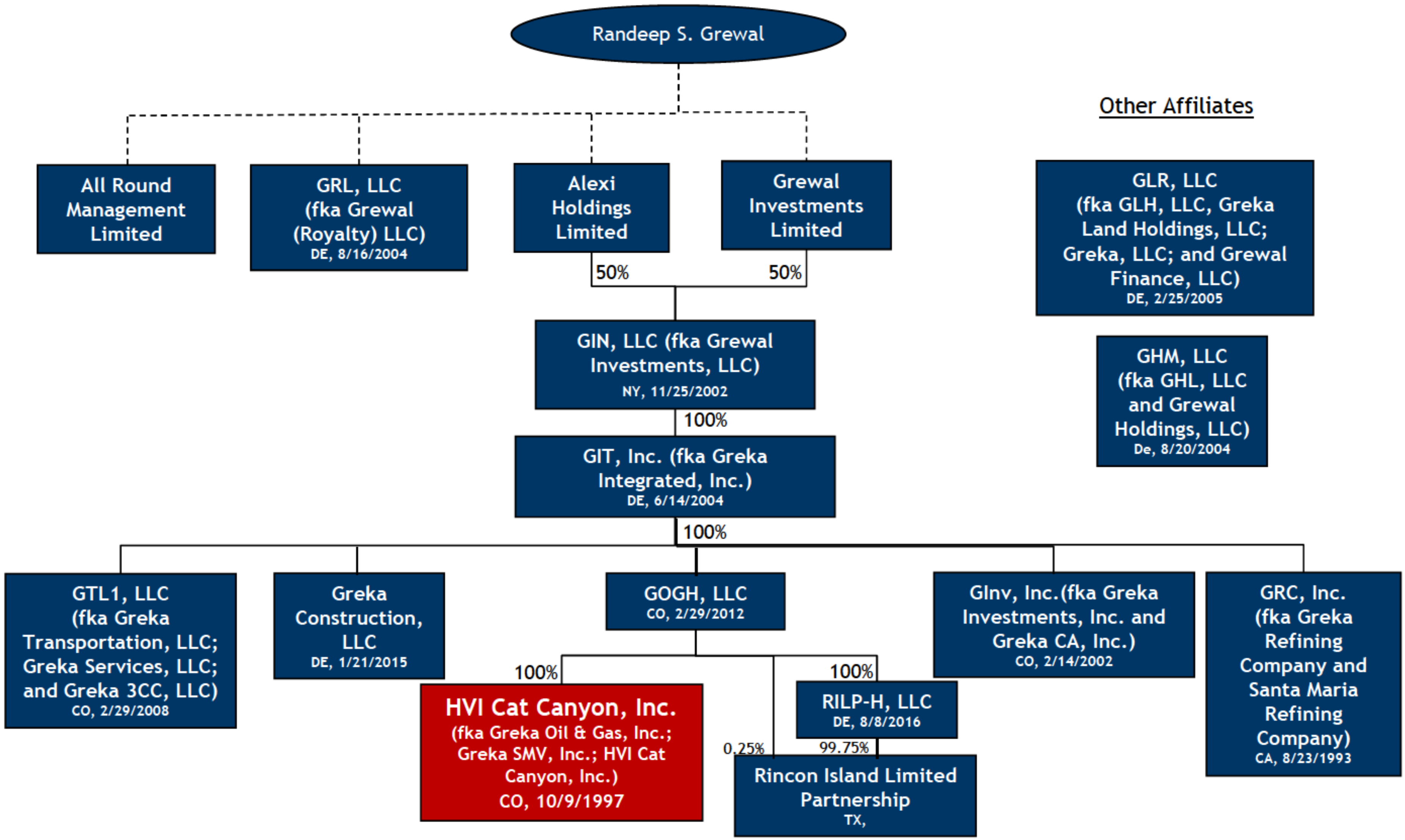
[106] Deposition of Randeep Grewal on October 12, 2016, p. 274.

[107] Deposition of Randeep Grewal on October 12, 2016, p. 308.

[108] Rincon Island Limited Partnership Chapter 11 bankruptcy in the U.S. Bankruptcy Court for the Northern District of Texas. Agreed Final Order Approving Use of Cash Collateral and Approving Post-Petition Financing. Document 53. Filed September 21, 2016.

[109] Rincon Island Limited Partnership Chapter 11 bankruptcy in the U.S. Bankruptcy Court for the Northern District of Texas. Opposition by the California State Lands Commission Re: Debtor's Motion for Final Order Authorizing Use of Cash Collateral and Approving Post-Petition Financing Pursuant to Section 364(c) and (d); and Declarations of Seth Blackmon and Mitchel Rishe in Support. Document 47. Filed September 16, 2016. p. 9

Exhibit 1: HVI Cat Canyon, Inc. Organizational Chart



Sources: EPA9_0276083, Testimony of Susan Whalen on October 4, 2016, p. 45-57, Greka Integrated 2015 Tax Returns Form 851 (HVI082803); Secretary of State filings.

Exhibit 2: HVI Cat Canyon, Inc. and Subsidiary Consolidated Balance Sheet

row	*As of December 31,*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Q3 2016
1	**Assets**												
2	Current assets:												
3	Cash and cash equivalents	$ 5,833,651	$ 33,908	$ 1,975,448	$ 6,424,105	$ -	$ 220,082	$ 1,719,492	$ -	$ -	$ -	$ -	$ 310,345
4	Accounts receivable trade	$ 2,887,239	$ 2,456,354	$ 3,845,339	$ 672,639	$ 1,270,989	$ 1,143,772	$ 1,952,044	$ 1,472,477	$ 7,565,481	$ 879,446	$ 584,104	$ 649,432
5	Inventory	$ 540,486	$ 590,061	$ 1,729,753	$ 245,477	$ 676,456	$ 403,274	$ 242,325	$ 408,776	$ 236,953	$ 87,643	$ 53,092	$ 56,725
6	Receivables from affiliates, net	$ 14,511,408	$ 6,460,057	$ 18,733,500	$ 4,546,868	$ 3,084,432	$ 3,199,891	$ 13,112,609	$ 7,598,312	$ -	$ -	$ -	$ -
7	Other current assets	$ 268,115	$ 150,478	$ 1,108,239	$ 2,590,329	$ 472,207	$ 1,294,552	$ -	$ -	$ -	$ 102,520	$ -	$ -
8	**Total Current Assets**	**$ 24,040,899**	**$ 9,690,858**	**$ 27,392,279**	**$ 14,479,418**	**$ 5,504,084**	**$ 6,261,571**	**$ 17,026,470**	**$ 9,479,565**	**$ 7,802,434**	**$ 1,069,609**	**$ 637,196**	**$ 1,016,502**
9	Oil & gas properties (full cost method)	$ 68,600,827	$ 75,845,848	$ 85,377,842	$ 92,794,621	$ 97,450,760	$ 104,962,367	$ 116,071,638	$ 123,923,373	$ 138,118,954	$ 147,568,652	$ 151,541,357	$ 134,357,295
10	Plant and equipment	$ 1,467,112	$ 1,955,901	$ 2,064,006	$ 2,036,052	$ 2,068,212	$ 2,317,762	$ 255,397	$ 281,716	$ 281,716	$ 318,444	$ 318,444	$ 291,557
11	less Depreciation & Depletion	$ (5,434,576)	$ (7,421,227)	$ (8,488,406)	$ (8,831,878)	$ (11,491,354)	$ (14,321,613)	$ (17,736,662)	$ (19,118,074)	$ (24,290,876)	$ (31,799,851)	$ (39,938,141)	$ (41,885,720)
12	Total PPE less deprec. & depletion			$ 78,953,442	$ 85,998,795	$ 88,027,618	$ 92,958,516	$ 98,590,373	$ 105,087,015	$ 114,109,794	$ 116,087,245	$ 111,921,660	$ 92,763,132
14	Receivable from affiliate, net	$ 76,141,188	$ 89,420,996	$ 96,808,332	$ 103,246,023	$ 117,802,672	$ 84,162,901	$ 81,926,531	$ 74,836,183	$ -	$ -	$ 64,156,445	$ 113,765,055
15	Deferred tax asset	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 68,246,959	$ 73,120,678	$ -	$ -
16	Other assets, net	$ 9,193,139	$ 8,134,635	$ 6,343,760	$ 6,032,599	$ 5,401,045	$ 5,265,307	$ 5,073,569	$ 5,835,315	$ 5,671,153	$ 4,988,039	$ 4,900,283	$ 2,926,700
17	**Total Assets**	**$ 174,008,589**	**$ 177,627,011**	**$ 209,497,813**	**$ 209,756,835**	**$ 216,735,419**	**$ 188,648,295**	**$ 202,616,943**	**$ 195,238,078**	**$ 195,830,340**	**$ 195,265,571**	**$ 181,615,584**	**$ 210,471,389**
18	**Liabilities and Stockholders' Equity**												
19	**Current liabilities**												
20	Bank overdraft	$ -	$ -	$ -	$ -	$ 680,793	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Accounts payable	$ 1,680,853	$ 1,864,867	$ 1,226,041	$ 1,719,785	$ 2,079,790	$ 2,179,952	$ 2,408,346	$ 4,247,357	$ 3,464,296	$ 5,593,323	$ 7,810,060	$ 8,684,975
22	Accrued expenses	$ 1,096,574	$ 2,146,811	$ 2,385,724	$ 2,103,674	$ 3,010,596	$ 4,020,716	$ 3,826,303	$ 3,665,466	$ 2,986,904	$ 3,645,711	$ 3,588,227	$ 4,067,719
23	Deferred revenue	$ -	$ -	$ 14,949,882	$ 16,017,998	$ 3,784,000	$ 12,404,075	$ 14,309,713	$ 14,245,178	$ 12,258,482	$ 10,704,227	$ -	$ -
24	Long-term debt- current portion	$ -	$ -	$ -	$ 35,900,000	$ -	$ 550,000	$ 425,000	$ 397,222	$ 397,222	$ -	$ -	$ -
25	Royalties payable	$ 3,252,448	$ 4,710,913	$ 3,105,438	$ 4,943,494	$ 4,173,330	$ 4,822,532	$ 6,079,345	$ 6,814,052	$ 9,355,013	$ 9,794,882	$ 9,970,267	$ 10,170,418
26	Notes payable- related parties	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,819,835	$ -	$ -
27	VPP obligation payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 71,586,027	$ 96,675,242	$ -	$ -
29	**Total Current Liabilities**	**$ 6,029,875**	**$ 8,722,591**	**$ 21,667,085**	**$ 60,684,951**	**$ 13,728,509**	**$ 23,977,275**	**$ 27,048,707**	**$ 29,369,275**	**$ 100,047,944**	**$ 169,233,220**	**$ 21,368,554**	**$ 22,923,112**
30	Long-term debt	$ 150,000,000	$ 150,000,000	$ 32,900,000	$ -	$ 35,900,000	$ 1,450,000	$ 975,000	$ 541,667	$ 108,333	$ -	$ -	$ 101,857,772
31	Note payable- related party	$ -	$ -	$ -	$ 21,747,783	$ 26,543,683	$ 29,910,086	$ 33,632,712	$ 38,124,863	$ 36,991,536	$ -	$ 49,218,287	$ 61,644,244
32	VPP obligation payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 115,766,508	$ -
33	Deferred revenue	$ -	$ -	$ 133,967,741	$ 119,296,556	$ 128,517,650	$ 114,924,163	$ 110,188,630	$ 99,302,061	$ 94,166,343	$ 89,835,204	$ 97,009,716	$ -
34	Asset retirement obligation	$ 1,508,845	$ 1,635,183	$ 1,848,483	$ 2,130,664	$ 2,444,903	$ 2,756,031	$ 3,509,261	$ 3,869,261	$ 4,490,700	$ 4,535,049	$ 3,653,565	$ -
35	Other liabilities	$ 1,195,105	$ 1,195,105	$ 1,233,093	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,923,565
36	**Total Liabilities**	**$ 158,733,825**	**$ 161,552,879**	**$ 191,616,402**	**$ 203,859,954**	**$ 207,134,745**	**$ 173,017,555**	**$ 175,354,310**	**$ 171,207,127**	**$ 235,804,856**	**$ 263,603,473**	**$ 287,016,630**	**$ 190,348,693**
37	**Shareholders' Equity**												
38	Common stock												$ 21,989,557
40	Retained Earnings	$ 15,274,764	$ 16,075,132	$ 17,881,301	$ 5,896,881	$ 9,600,674	$ 15,630,740	$ 27,262,633	$ 24,030,951	$ (39,974,516)	$ (68,337,902)	$(105,401,046)	$ (1,866,861)
41	**Total shareholders' equity**	**$ 15,274,764**	**$ 16,075,132**	**$ 17,881,301**	**$ 5,896,881**	**$ 9,600,674**	**$ 15,630,740**	**$ 27,262,633**	**$ 24,030,951**	**$ (39,974,516)**	**$ (68,337,902)**	**$(105,401,046)**	**$ 20,122,696**
42	**Total Liab. & Shareholders' Equity**	**$ 174,008,589**	**$ 177,628,011**	**$ 209,497,703**	**$ 209,756,835**	**$ 216,735,419**	**$ 188,648,295**	**$ 202,616,943**	**$ 195,238,078**	**$ 195,830,340**	**$ 195,265,571**	**$ 181,615,584**	**$ 210,471,389**

Sources:

GREKA Oil & Gas Inc. and Subsidiary Consolidated Financial Statements, Years Ended December 31, 2005-2015. HVIFIN0002063, HVI084312, HVI065327, HVI065309, HVI076575, HVIFIN0000628, and HVI084234.

HVI Cat Canyon, Inc. Integrated Unaudited Financials: Consolidating Balance Sheet March 31, June 30, September 30th, 2016. HVI084281 to HVI084289

Exhibit 3: HVI Cat Canyon, Inc. and Subsidiary Consolidated Income Statement

row	Year ending Dec 31:	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
1	Revenues	$ 30,694,687	$ 37,296,819	$ 39,225,078	$ 37,730,678	$ 31,066,181	$ 39,708,896	$ 56,937,728	$ 49,334,083	$ 62,400,628	$60,368,454
2	Operating Expenses:										
3	Production Costs	$ 10,451,465	$ 11,170,134	$ 12,244,413	$ 19,158,469	$ 14,903,999	$ 17,660,685	$ 28,985,295	$ 36,443,077	$ 36,569,472	$38,389,990
4	Sales, G&A	$ 1,939,887	$ 3,410,107	$ 2,623,546	$ 8,589,334	$ 3,922,701	$ 7,868,096	$ 8,293,372	$ 6,694,978	$ 6,828,518	$8,055,069
5	Depr, depl & amort	$ 1,896,538	$ 1,998,099	$ 1,061,494	$ 343,472	$ 2,973,714	$ 3,141,387	$ 3,607,030	$ 1,741,412	$ 5,598,668	$7,553,324
6	**Operating Income**	**$ 16,406,797**	**$ 20,718,479**	**$ 23,295,625**	**$ 9,639,403**	**$ 9,265,767**	**$ 11,038,728**	**$ 16,052,031**	**$ 4,454,616**	**$ 13,403,970**	**$6,370,071**
7	Other Income (Expenses):										
8	Interest expense	$ (8,639,586)	$ (19,610,939)	$ (21,156,009)	$ (21,768,466)	$ (5,899,152)	$ (5,205,394)	$ (4,410,821)	$ (7,836,117)	$ (7,328,845)	($13,895,004)
9	VPP volume shortfall	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (27,904,034)	($21,030,172)
10	VPP volume retail	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Other income	$ (170,120)	$ 123,795	$ 639,106	$ 144,644	$ 337,178	$ 196,732	$ (9,317)	$ 149,819	$ 1,045,970	$191,718
12	**Other expense, net**	**$ (8,809,706)**	**$ (19,487,144)**	**$ (20,516,903)**	**$ (21,623,822)**	**$ (5,561,974)**	**$ (5,008,662)**	**$ (4,420,138)**	**$ (7,686,298)**	**$ (34,186,909)**	**($34,733,458)**
13	Income before inc taxes	$ 7,597,091	$ 1,231,335	$ 2,778,722	$ (11,984,419)	$ 3,703,793	$ 6,030,066	$ 11,631,893	$ (3,231,682)	$ (20,782,939)	($28,363,387)
14	Provision for income tax	$ 2,858,812	$ 430,967	$ 972,553	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	**Net (loss) income**	**$ 4,738,279**	**$ 800,368**	**$ 1,806,169**	**$ (11,984,419)**	**$ 3,703,793**	**$ 6,030,066**	**$ 11,631,893**	**$ (3,231,682)**	**$ (20,782,939)**	**($28,363,387)**

GREKA Oil & Gas Inc. and Subsidiary Consolidated Financial Statements, Years Ended December 31, 2005-2015. HV FIN0002063, HVI084312, HV 065327, HVI065309, HV 076575, HVIF N0000628, and HVI084234.

HVI Cat Canyon, Inc. Integrated Unaudited Financials: Consolidating Balance Sheet March 31, June 30, September 30th, 2016. HVI084281 to HVI084289

Exhibit 3: HVI Cat Canyon, Inc. and Subsidiary Consolidated Income Statement

row	Year ending Dec 31:	2015	Q1 2016	Q2 2016	Q3 2016	Q1-Q3 2016
1	Revenues	$30,728,404	$3,480,779	$4,620,332	$4,747,689	$12,848,800
2	Operating Expenses:					
3	Production Costs	$25,241,598	$4,606,192	$4,024,467	$4,287,179	$12,917,838
4	Sales, G&A	$6,356,620	$974,532	$730,852	$973,584	$2,678,968
5	Depr, depl & amort	$8,498,290	$1,140,026	$1,062,146	$1,048,313	$3,250,485
6	**Operating Income**	**($9,368,104)**	**($3,239,971)**	**($1,197,133)**	**($1,561,387)**	**($5,998,491)**
7	Other Income (Expenses):					
8	Interest expense	($14,252,076)	($1,728,705)	($2,362,731)	($3,172,144)	($7,263,580)
9	VPP volume shortfall	($13,381,921)	$ -	$ -	$ -	$ -
10	VPP volume retail	$ -	($2,597,355)	$2,597,355	$ -	$ -
11	Other income	($61,042)	$16,096	$112,754,615	($59,701)	$112,711,010
12	**Other expense, net**	**($27,695,039)**	**($4,309,964)**	**$112,989,239**	**($3,231,845)**	**$105,447,430**
13	Income before inc taxes	($37,063,143)	($7,549,935)	$111,792,106	($4,793,232)	$99,448,939
14	Provision for income tax	$ -	$ -	$ -	$ -	$ -
15	**Net (loss) income**	**($37,063,143)**	**($7,549,935)**	**$111,792,106**	**($4,793,232)**	**$99,448,939**

Sources:

GREKA Oil & Gas Inc. and Subsidiary Consolidated Financial Statements, Years Ended December 31, 2005-2015. HVIF N0002063, HV 084312, HVI065327, HV 065309, HVI076575, HV FIN0000628, and HVI084234.

HVI Cat Canyon, Inc. Integrated Unaudited Financials: Consolidating Balance Sheet March 31, June 30, September 30th, 2016. HVI084281 to HVI084289

Exhibit 4: HVI Cat Canyon, Inc. and Subsidiary Consolidated Statement of Cash Flows

row	Year ending Dec 31:	2005	2006	2007	2008	2009	2010	2011	2012	2013
1	**Cash flows from operating activities**									
2	Net income (loss)	$ 4,738,279	$ 800,368	$ 1,806,169	$ (11,984,419)	$ 3,703,793	$ 6,030,066	$ 11,631,893	$ (3,231,682)	$ (20,782,939)
3	Deprec., depletion and amort.	$ 1,896,538	$ 1,998,099	$ 1,061,494	$ 343,472	$ 2,973,714	$ 3,141,387	$ 3,607,030	$ 1,741,412	$ 5,598,668
4	Interest included in deferred revenue	$ -	$ -	$ -	$ -	$ 4,030,164	$ -	$ 725,806	$ 2,110,335	$ -
5	Interest capitalized into VPP obligation payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,581,867
6	Interest capitalized into principal on related party debt	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ 4,714,985
7	Amortization of deferred revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,555,701)	$ (13,061,439)	$ (9,244,816)
8	Non-cash interest expense as a result of PIK election	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Non-Cash income as a result of loan restructure	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Non cash settlement	$ -	$ -	$ -	$ -	$ -	$ 2,000,000	$ -	$ -	$ -
11	Interest capitalized into principal on LT debt	$ -	$ -	$ -	$ -	$ -	$ 3,366,403	$ 3,722,626	$ 4,492,151	$ -
12	Accretion expense	$ -	$ -	$ 213,300	$ 282,181	$ -	$ -	$ -	$ -	$ -
13	VPP volume shortfall	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,904,034
14	**Changes in operating assets and liabilities:**									
15	Accounts receivable	$ (467,497)	$ 430,885	$ (1,388,985)	$ 3,172,700	$ (598,350)	$ 127,217	$ (808,272)	$ 479,567	$ (6,093,004)
16	Other current assets	$ (112,912)	$ 117,637	$ (957,761)	$ (1,482,090)	$ 2,118,122	$ (822,346)	$ 1,294,552	$ -	$ -
17	Receivables from affiliates	$ (10,498,961)	$ 8,051,351	$ 5,726,557	$ 14,186,632	$ 1,462,436	$ (115,459)	$ (78,036)	$ -	$ -
18	Inventory	$ (340,963)	$ (49,575)	$ (1,139,692)	$ 1,484,276	$ (430,979)	$ 273,182	$ 160,949	$ (166,451)	$ 171,823
19	VPP proceeds	$ -	$ -	$ 30,815,473	$ -	$ -	$ -	$ -	$ -	$ -
20	Amortization of deferred revenues	$ -	$ -	$ (12,582,267)	$ (13,603,179)	$ (7,043,068)	$ (4,973,412)	$ -	$ -	$ -
21	Intercompany	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,589,224
22	Other assets	$ (3,691,651)	$ 1,058,504	$ 1,790,875	$ 311,161	$ 631,554	$ 135,737	$ 191,738	$ (761,746)	$ 164,162
23	Bank overdrafts	$ -	$ -	$ -	$ -	$ 680,793	$ (680,793)	$ -	$ -	$ -
24	VPP obligation payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Accounts payable and accrued expenses	$ (1,075,313)	$ 1,234,251	$ (910,491)	$ 211,693	$ 1,266,928	$ 1,110,287	$ 33,981	$ 1,678,174	$ (1,461,623)
26	Royalties payable	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,256,813	$ 734,707	$ 2,540,961
27	Other liabilities	$ 2,437,922	$ 1,584,803	$ (372,382)	$ 604,963	$ (770,164)	$ 649,199	$ -	$ -	$ -
28	**Net Cash Provided (used) by Operating Activities**	**$ (7,114,558)**	**$ 15,226,323**	**$ 24,062,290**	**$ (6,472,610)**	**$ 8,024,943**	**$ 10,241,468**	**$ 18,183,379**	**$ (5,984,972)**	**$ 12,683,342**
29	**Cash flows from investing activities**									
30	Investment in oil and gas property and equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (14,000,008)
31	Advance to affiliate	$ (76,141,188)	$ (13,279,808)	$ (10,387,336)	$ 15,310,092	$ (9,760,749)	$ (2,260,229)	$ (7,598,312)	$ 12,604,645	$ 1,750,000
32	Proceeds from sale of oil and gas properties	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,000,000	$ -
33	Purchases of oil and gas property and equipment	$ (5,910,603)	$ (7,746,258)	$ (9,633,414)	$ (7,388,825)	$ (4,688,299)	$ (7,761,157)	$ (8,485,657)	$ (11,878,054)	$ -
34	**Net cash provided by (used in) investing activities**	**$ (82,051,791)**	**$ (21,026,066)**	**$ (20,020,750)**	**$ 7,921,267**	**$ (14,449,048)**	**$ (10,021,386)**	**$ (16,083,969)**	**$ 4,726,591**	**$ (12,250,008)**
35	**Cash flows from financing activities**									
36	Repayment of debt	$ -	$ -	$ (2,100,000)	$ -	$ -	$ -	$ (600,000)	$ (461,111)	$ (433,334)
37	Intercompany, net	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38	Note payable related party	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Proceeds from debt	$ -	$ -	$ -	$ 3,000,000	$ -	$ -	$ -	$ -	$ -
40	Increase in long-term debt	$ 95,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41	**Net Cash provided by financing activities**	**$ 95,000,000**	**$ -**	**$ (2,100,000)**	**$ 3,000,000**	**$ -**	**$ -**	**$ (600,000)**	**$ (461,111)**	**$ (433,334)**
42	**Net increase (decrease) in cash and cash equivalents**	**$ 5,833,651**	**$ (5,799,743)**	**$ 1,941,540**	**$ 4,448,657**	**$ (6,424,105)**	**$ 220,082**	**$ 1,499,410**	**$ (1,719,492)**	**$ -**
43	**Cash and cash equivalents, beginning of year**	$ -	$ 5,833,651	$ 33,908	$ 1,975,448	$ 6,424,105	$ -	$ 220,082	$ 1,719,492	$ -
44	**Cash and cash equivalents, end of year**	**$ 5,833,651**	**$ 33,908**	**$ 1,975,448**	**$ 6,424,105**	**$ -**	**$ 220,082**	**$ 1,719,492**	**$ -**	**$ -**

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Exhibit 4: HVI Cat Canyon, Inc. and Subsidiary Consolidated Statement of Cash Flows

row	Year ending Dec 31:	2005	2006	2007	2008	2009	2010	2011	2012	2013
45	Cash paid for interest	$ 8,269,222	$ 17,286,547	$ 18,289,056	$ 23,061,365	$ 2,493,462	$ 1,826,991	$ -	$ -	$ -
46	Change to net oil and gas properties related to asset retirement obligation liabilities	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	VPP proceeds lent to related party	$ -	$ -	$ 15,000,000	$ -	$ -	$ -	$ -	$ -	$ -
47	VPP proceeds used to pay interest expense on long-term debt	$ -	$ -	$ 684,527	$ -	$ -	$ -	$ -	$ -	$ -
48	VPP proceeds used to pay long-term debt	$ -	$ -	$ 115,000,000	$ -	$ -	$ -	$ -	$ -	$ -
49	Intercompany extinguishment of debt	$ -	$ -	$ -	$ -	$ -	$ 35,900,000	$ -	$ -	$ -
50	Accrued interest on intercompany receivable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51	Reduction of intercompany receivable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	Issuance of note payable for settlement of liability	$ -	$ -	$ -	$ -	$ -	$ 2,000,000	$ -	$ -	$ -
53	Additions to property and asset retirement oblig.	$ -	$ -	$ -	$ -	$ -	$ -	$ 561,248	$ -	$ 195,573

Sources: GREKA Oil & Gas Inc. and Subsidiary, Consolidated Financial Statements, Years Ended December 31, 2005-2015. HVIF N0002063, HV 084312, HV 065327, HVI065309, HV 076575, HVIF N0000628, and HVI084234.

HVI Cat Canyon, Inc. Integrated Unaudited Financials: Consolidating Statement of Cash Flows March 31, June 30, September 30th, 2016. HV 084281 to HVI084289.

Exhibit 4: HVI Cat Canyon, Inc. and Subsidiary Consolidated
Statement of Cash Flows

row	Year ending Dec 31:	2014	2015	Q1 2016	Q2 2016	Q3 2016	Q1-Q3 2016
1	**Cash flows from operating activities**						
2	Net income (loss)	$ (28,363,387)	$ (37,063,143)	$ (7,549,935)	$ 111,792,106	$ (4,793,196)	$ 99,448,975
3	Deprec., depletion and amort.	$ 7,553,324	$ 8,498,290	$ 1,050,026	$ 1,062,146	$ 1,048,313	$ 3,160,485
4	Interest included in deferred revenue	$ -	$ -	$ -	$ -	$ -	$ -
5	Interest capitalized into VPP obligation payable	$ 4,059,043	$ 5,709,345	$ -	$ -	$ -	$ -
6	Interest capitalized into principal on related party debt	$ 5,828,300	$ 6,398,452	$ -	$ -	$ -	$ -
7	Amortization of deferred revenues	$ (5,885,394)	$ (3,529,715)	$ -	$ -	$ -	$ -
8	Non-cash interest expense as a result of PIK election	$ -	$ -	$ -	$ -	$ 1,288,123	$ 1,288,123
9	Non-Cash income as a result of loan restructure	$ -	$ -	$ -	$ (114,803,931)	$ -	$ (114,803,931)
10	Non cash settlement	$ -	$ -	$ -	$ -	$ -	$ -
11	Interest capitalized into principal on LT debt	$ -	$ -	$ -	$ -	$ -	$ -
12	Accretion expense	$ -	$ -	$ -	$ -	$ -	$ -
13	VPP volume shortfall	$ 21,030,172	$ 13,381,921	$ -	$ -	$ -	$ -
14	**Changes in operating assets and liabilities:**						$ -
15	Accounts receivable	$ 6,685,769	$ 295,342	$ (92,072)	$ (12,894)	$ 38,823	$ (66,143)
16	Other current assets	$ -	$ -	$ -	$ -	$ -	$ -
17	Receivables from affiliates	$ -	$ -	$ -	$ -	$ -	$ -
18	Inventory	$ 149,310	$ 34,551	$ 9,780	$ (52,673)	$ 39,260	$ (3,633)
19	VPP proceeds	$ -	$ -	$ -	$ -	$ -	$ -
20	Amortization of deferred revenues	$ -	$ -	$ -	$ -	$ -	$ -
21	Intercompany	$ (4,873,720)	$ 8,964,233	$ -	$ -	$ -	$ -
22	Other assets	$ 580,861	$ 190,275	$ 10,349	$ (1,372,857)	$ (936,919)	$ (2,299,427)
23	Bank overdrafts	$ -	$ -	$ -	$ -	$ -	$ -
24	VPP obligation payable	$ -	$ -	$ 2,597,355	$ -	$ -	$ 2,597,355
25	Accounts payable and accrued expenses	$ 2,787,834	$ 2,159,253	$ 588,886	$ 2,273,726	$ 850,565	$ 3,713,177
26	Royalties payable	$ 439,869	$ 175,385	$ 6,029,538	$ 107,770	$ 38,254	$ 6,175,562
27	Other liabilities	$ -	$ -	$ (5,885,301)	$ -	$ -	$ (5,885,301)
28	**Net Cash Provided (used) by Operating Activities**	**$ 9,991,981**	**$ 5,214,189**	**$ (3,241,374)**	**$ (1,006,607)**	**$ (2,426,777)**	**$ (6,674,758)**
29	**Cash flows from investing activities**						
30	Investment in oil and gas property and equipment	$ (9,486,426)	$ (5,214,189)	$ -	$ -	$ -	$ -
31	Advance to affiliate	$ -	$ -	$ -	$ -	$ -	$ -
32	Proceeds from sale of oil and gas properties	$ -	$ -	$ -	$ -	$ -	$ -
33	Purchases of oil and gas property and equipment	$ -	$ -	$ (442,097)	$ (510,282)	$ (872,804)	$ (1,825,183)
34	**Net cash provided by (used in) investing activities**	**$ (9,486,426)**	**$ (5,214,189)**	**$ (442,097)**	**$ (510,282)**	**$ (872,804)**	**$ (1,825,183)**
35	**Cash flows from financing activities**						
36	Repayment of debt	$ (505,555)	$ -	$ -	$ -	$ -	$ -
37	Intercompany, net	$ -	$ -	$ 2,013,215	$ (1,023,749)	$ 185,119	$ 1,174,585
38	Note payable related party	$ -	$ -	$ 1,722,596	$ 2,474,792	$ 3,328,569	$ 7,525,957
39	Proceeds from debt	$ -	$ -	$ -	$ -	$ -	$ -
40	Increase in long-term debt	$ -	$ -	$ -	$ -	$ -	$ -
41	**Net Cash provided by financing activities**	**$ (505,555)**	**$ -**	**$ 3,735,811**	**$ 1,451,043**	**$ 3,513,688**	**$ 8,700,542**
42	**Net increase (decrease) in cash and cash equivalents**	**$ -**	**$ -**	**$ 52,340**	**$ (65,846)**	**$ 214,107**	**$ 200,601**
43	**Cash and cash equivalents, beginning of year**	$ -	$ -	$ 119,362	$ 171,702	$ 96,238	$ -
44	**Cash and cash equivalents, end of year**	**$ -**	**$ -**	**$ 171,702**	**$ 105,856**	**$ 310,345**	$ -

May Reflect Confidential Business Information

Exhibit 4: HVI Cat Canyon, Inc. and Subsidiary Consolidated
Statement of Cash Flows

row	Year ending Dec 31:	2014	2015	Q1 2016	Q2 2016	Q3 2016	Q1-Q3 2016
45	Cash paid for interest	$ 4,007,661	$ 2,144,279	$ -	$ -	$ -	$ -
46	Change to net oil and gas properties related to asset retirement obligation liabilities	$ -	$ (1,241,484)	$ -	$ -	$ -	$ -
47	VPP proceeds lent to related party	$ -	$ -	$ -	$ -	$ -	$ -
47	VPP proceeds used to pay interest expense on long-term debt	$ -	$ -	$ -	$ -	$ -	$ -
48	VPP proceeds used to pay long-term debt	$ -	$ -	$ -	$ -	$ -	$ -
49	Intercompany extinguishment of debt	$ -	$ -	$ -	$ -	$ -	$ -
50	Accrued interest on intercompany receivable	$ 1,388,907	$ -	$ -	$ -	$ -	$ -
51	Reduction of intercompany receivable	$ (1,900,000)	$ -	$ -	$ -	$ -	$ -
52	Issuance of note payable for settlement of liability	$ -	$ -	$ -	$ -	$ -	$ -
53	Additions to property and asset retirement oblig.	$ -	$ -	$ -	$ -	$ -	$ -

Sources: GREKA Oil & Gas Inc. and Subsidiary, Consolidated Financial Statements, Years Ended December 31, 2005-2015. HVIFIN0002063, HVI084312, HVI065327, HV 065309, HVI076575, HVIFIN0000628, and HVI084234.

HVI Cat Canyon, Inc. Integrated Unaudited Financials: Consolidating Statement of Cash Flows March 31, June 30, September 30th, 2016. HVI084281 to HV 084289.

INDUSTRIAL ECONOMICS, INCORPORATED

Appendix A

J O A N K . M E Y E R

Dr. Meyer's primary areas of expertise are economic, financial, and policy analysis. As a Principal at Industrial Economics, Incorporated, she has more than 25 years of experience in analyzing the economic, business, and financial dimensions of natural resource and environmental issues. She regularly testifies as an expert witness in federal, state and administrative courts, and supports litigation teams on the economic and financial aspects of cases involving air, water, and hazardous waste issues. Her testimony in these cases has encompassed the financial condition of businesses and individuals, the economic benefit gained by companies from regulatory noncompliance, fraudulent conveyance, successor liability, piercing the corporate veil, de facto mergers, regional economic impact of businesses and industries, and issues relating to cost/benefit analysis. She also assesses the likely impacts of proposed reorganization plans for companies in Chapter 11 bankruptcy.

Dr. Meyer's recent project experience includes the following:

- Directing the development of strategies and approaches to assess the financial condition and corporate performance of businesses, individuals, government and not-for-profit organizations to pay penalties, afford clean-up expenditures and other investments, and meet financial assurance requirements.
- Tracing complex corporate structures, transactions, and financial and corporate operations in matters involving questions about corporate successors, corporate control, piercing the corporate veil, de facto merger, and fraudulent conveyance.
- Estimating the economic benefit gained by violators from noncompliance or delayed compliance with regulatory requirements.
- Conducting training and seminars in corporate financial analysis and related topics.

Dr. Meyer received her B.S. degree in Agricultural and Resource Economics (with honors) from the University of California, Berkeley and her M.S. and Ph.D. degrees from Cornell University (Major field: Environmental and Natural Resource Economics; Minor fields: Corporate Finance and Econometrics/Quantitative Methods). Prior to joining IEc, Dr. Meyer was Senior Associate at The Cadmus Group, Inc., Associate at Putnam, Hayes & Bartlett, Inc., and Research Analyst in the Department of Policy Development and Planning, Governor's Office, State of Alaska. She is a member of the American Economics Association and the Agricultural and Applied Economics Association.

Financial and Economic Analysis

- Assessing the financial condition and ability to pay of corporations, limited liability companies, master limited partnerships, partnerships, sole proprietorships, individuals, and municipalities and other public entities to afford environmental expenditures, penalties and/or fines.
- Estimating the economic benefits gained from delayed and/or avoided compliance by violators in the hardrock mining, real estate development, natural gas, petroleum, meat processing, agriculture, coal, timber, wood products, and other industries with applicable environmental and other regulations.
- Tracing the corporate successors to owners and operators by analyzing corporate and financial records of mergers, asset purchase agreements, reorganizations, and other complex business transactions.
- Providing expert financial analysis of businesses in Chapter 11 bankruptcy protection for companies in the battery, coal, oil & gas, aluminum, chemical, hazardous and non-hazardous waste disposal, hard rock mining, and specialty metals industries. Analyzing the corporate history and organizational structure, the ability of companies to successfully restructure their operations while adequately providing for their environmental liabilities, and the viability of alternative financial responsibility proposals.
- Assessing the financial assurance mechanisms for companies with significant financial assurance responsibilities under the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation, and Liability Act, and /or the Surface Mining Control and Reclamation Act that were operating under Chapter 11 bankruptcy protection.
- Evaluating the corporate, financial, and organizational behavior of groups of affiliated businesses in order to determine the extent to which the affiliates adhere to corporate norms and are managed as independent entities.
- Leading the assessment of the financial gain realized by a pipeline operator from failure to appropriately maintain, upgrade, and monitor its system.
- Directing the financial analysis of inability to pay claims by Potentially Responsible Parties at more than 200 Superfund sites.
- Conducting the evaluation of the financial status and operation of businesses, individuals, and not-for-profit organizations involved in environmental enforcement actions.
- Estimating the economic benefit realized by a major defense contractor from the accounting treatment of site remediation costs in rates charged under government contracts.
- Estimating the economic benefits realized by a major aerospace company through the voluntary participation in government programs.
- Managing litigation support activities in a case involving a mining operation and its relationship to its corporate owners. Conducting detailed analysis of the aspects of a parent-subsidiary operating relationship over more than four decades as it pertained to norms of typical corporate behavior and various elements of corporate control.

Testimony within the Past Four Years

- In the matter of In re: Alpha Natural Resources, Inc. (U.S. Bankruptcy Court for the Eastern District of Virginia, Richmond Division), provided deposition testimony about the likely financial viability of the reorganization plan proposed for a coal company over the next five years including its ability to meet its reclamation and other environmental liabilities.
- In the matter of Harris County, Texas and the Texas Commission on Environmental Quality v. International Paper Company, et al. (District Court of Harris County, Texas), provided trial and deposition testimony about the corporate successors to a paper mill and the company that disposed of waste from the mill in the 1960s and the associated penalties.
- In the matter of Lockheed Martin v. United States of America (U.S. District Court, District of Columbia), provided trial and deposition testimony about Lockheed's recovery of remediation costs incurred at a Superfund site through overhead charges under its contracts with the United States and the economic benefit that would be gained by Lockheed from an additional CERCLA payment from the United States.
- In the matter of the United States of America and the South Carolina Department of Health and Environmental Control v. Albemarle Corporation (U.S. District Court, District of South Carolina), provided deposition testimony about the economic benefit gained by the defendant from noncompliance with Clean Air Act regulations.
- In the matter of the United States of America v. Federal Resources Corporation, et al. (U.S. District Court, District of Idaho), provided deposition testimony about the related parties to the defendants and the financial and corporate impact of a particular transaction in a case concerning CERCLA cost recovery.
- In the matter of the United States of America and the State of Nebraska v. STABL, Inc. (U.S. District Court, District of Nebraska), provided trial testimony about the economic benefit gained by the defendant from noncompliance with Clean Water Act regulations.
- In the matter of the United States of America v. ConAgra Grocery Products Company, LLC (U.S. District Court, District of Maine), provided deposition testimony regarding the corporate successors to former operators at a particular facility.
- In the matter of the United States of America v. Hamilton (U.S. District Court, District of Wyoming), provided deposition testimony about the economic benefit gained by the defendants from noncompliance with the Clean Water Act regulations.
- In the matter of TDY Holdings, LLC and TDY Industries, Inc. v. United States of America, United States Department of Defense, and Robert M. Gates (U.S. District Court, Southern District of California), provided trial and deposition testimony on the economic benefits gained by the plaintiffs and their predecessors at their San Diego facility as a result of transactions with military and other federal agencies.

Expert Testimony Rate

Case Preparation Rate, $214 per hour

Testimony Rate, $250 per hour

APPENDIX B | DOCUMENTS CONSIDERED

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159. United States of America and People of the State of California, ex rel. California Department of Fish and Wildlife and California Regional Water Board, Coastal Region, v. HVI Cat Canyon, Inc. f/k/a Greka Oil and Gas, Inc., Case No. CV 11-5097 FMO (SSx). HVI Cat Canyon, Inc.'s Response to California Regional Water Control Board Central Coast Region's Amended Interrogatories, Set 1. December 2, 2016.

Exhibit C: Supplemental Financial Condition Expert Report

SUPPLEMENTAL EXPERT REPORT OF DR. JOAN K. MEYER

HVI Cat Canyon, Inc.'s Finances and Transactions with Related Entities

United States et al. v. HVI Cat Canyon, Inc., f/k/a Greka Oil & Gas, Inc.,
CV 11-05097 FMO (SSx) (C.D. Cal.)

Prepared for:
United States Department of Justice
Environment and Natural Resources Division
Environmental Enforcement Section

Signature Joan K. Meyer

Date Mar-10-2017

SUMMARY OF UPDATES TO OPINIONS

I submitted an expert report in this matter dated February 9, 2017, addressing HVI Cat Canyon, Inc.'s finances and transactions with related entities.[1] My expert opinions were based upon deposition testimony, including the deposition of James Johnson taken on January 26, 2017. At the time of my initial expert report, the only transcript of this deposition available was a rough draft.[2] While I relied on this transcript for my initial report, this rough draft transcript contained many transcription codes, sentence fragments, and incorrect and misspelled words that were to be corrected in the finalized version. In this supplement, I account for information contained in James Johnson's final deposition transcript, produced on February 14, 2017.

At the time of my February 9, 2017 expert report, I assumed that HVI Cat Canyon, Inc. (HVI-CC) had been tracking intercompany activity in a finer detail internally than it reported on its audited financial statements. I assumed, for example, that HVI-CC maintained internal financial documents that track funds owed from GIT to HVI-CC as a result of the 2013 Tax-Sharing Agreement separately from recurring crude oil transactions with GRC. However, Mr. Johnson testified that HVI-CC tracks all intercompany transactions in one account no matter what the nature of the transaction or the related entity with which HVI-CC is transacting. For example, Mr. Johnson testified that ordinary transactions that occur every day, like crude oil sales from HVI-CC to an affiliate, would be tracked in the same account as debt owed to GIT related to refinancing activity.[3] Mr. Johnson testified that he expects all of the following activity to be blended in the intercompany account:

1. An increase in the amount due to HVI-CC reflecting a credit to HVI-CC from GIT under the 2005 Promissory Note with GIT;[4]
2. An increase in the amount due to HVI-CC reflecting a cash advance to GIT from HVI-CC of approximately $13 million in 2006;[5]
3. An increase in the amount due to HVI-CC reflecting HVI-CC's $15 million advance to an affiliate outside the group in 2007, followed by a decrease in the amount due to HVI-CC reflecting $15 million returned from an entity outside the group in 2008;[6]
4. A reduction in the amount due to HVI-CC by approximately $5 million in 2007 reflecting "activity" between HVI-CC and GIT that Mr. Johnson could not distinguished between oil and gas transactions or cash transfers;[7]
5. An increase in the amount due to HVI-CC by approximately $21 million between 2007 and 2009 reflecting oil and gas sales to an affiliate for which HVI-CC was not immediately payed;[8]

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[1] United States et al. v. HVI Cat Canyon, Inc., f/k/a Greka Oil & Gas, Inc., Expert Report of Joan K. Meyer: HVI Cat Canyon, Inc.'s Finances and Transactions with Related Entities, February 9, 2017.

[2] Rough Draft, 30(b)(6) Deposition of James W. Johnson, (BDO USA LP) on January 26, 2017.

[3] Deposition of James W. Johnson on January 26, 2017, p. 36.

[4] Ibid, pp. 44-45.

[5] Ibid, p. 61.

[6] Ibid, pp. 65-66.

[7] Ibid, pp. 77-79.

6. A reduction in the amount due to HVI-CC by $35.9 million in 2010 reflecting GIT paying off $35.9 million of HVI-CC's debt;[9]
7. A reduction in the amount due to HVI-CC by approximately $20 million (from approximately $84.1 million to approximately $64.2 million) between 2010 and 2015 reflecting ordinary oil and gas transactions between HVI-CC and its affiliates.[10]

Additionally, Mr. Johnson testified that interest never accrued in the intercompany account.[11]

In my previous expert report dated February 9, 2017, I had assumed that HVI-CC's long-term receivable from its affiliate that appeared in its 2015 audited financials was the amount owed from GIT related to the 2013 Tax-Sharing Agreement. The only explanation given for the long term receivable in HVI-CC's audited financials is that it is a result of the refinance of HVI-CC's debt in 2005, and there is no discussion suggesting that any of the transactions listed above are represented in that long-term receivable.[12] However, according to Mr. Johnson's testimony, in addition to accounting for the tax-sharing agreement, this long-term receivable represents a single intercompany account that currently includes cash advances, another debt refinance of $35.9 million, and amounts yet unpaid for oil and gas sales transacted between HVI-CC and its affiliates. Additionally, this intercompany account previously held a $15 million loan paid outside GIT's consolidated structure.

This evidence supports my opinion that HVI-CC is managed in concert with its affiliates. If HVI-CC were managed independently from its affiliates, it would keep separate intercompany accounts for each of its affiliates instead of consolidating all amounts owed to and from all affiliates into a single account. Additionally, if HVI-CC were managed independently from its affiliates, it would not consolidate funds it is owed in tax credits with funds it is owed in cash into a single account.

I may revise my opinions further as additional information becomes available to me. I reserve the right to supplement this report and my February 9, 2017 report.

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[8] Ibid, pp. 90-92.

[9] Ibid, pp.94-95.

[10] Ibid, pp. 97-107.

[11] Ibid, p. 48.

[12] Greka Oil & Gas, Inc. Consolidated Financial Statements, Years Ended December 31, 2005 to 2015, Bates Nos. HVIFIN0002063, HVI084312, HVI065327, HVI065309, HVI076575, HVIFIN0000628, and HVI084234.

APPENDIX B | SUPPLEMENTAL DOCUMENTS CONSIDERED

1. Deposition of James W. Johnson, January 26, 2017.

Exhibit D: Updated Financial Condition Expert Report Exhibits

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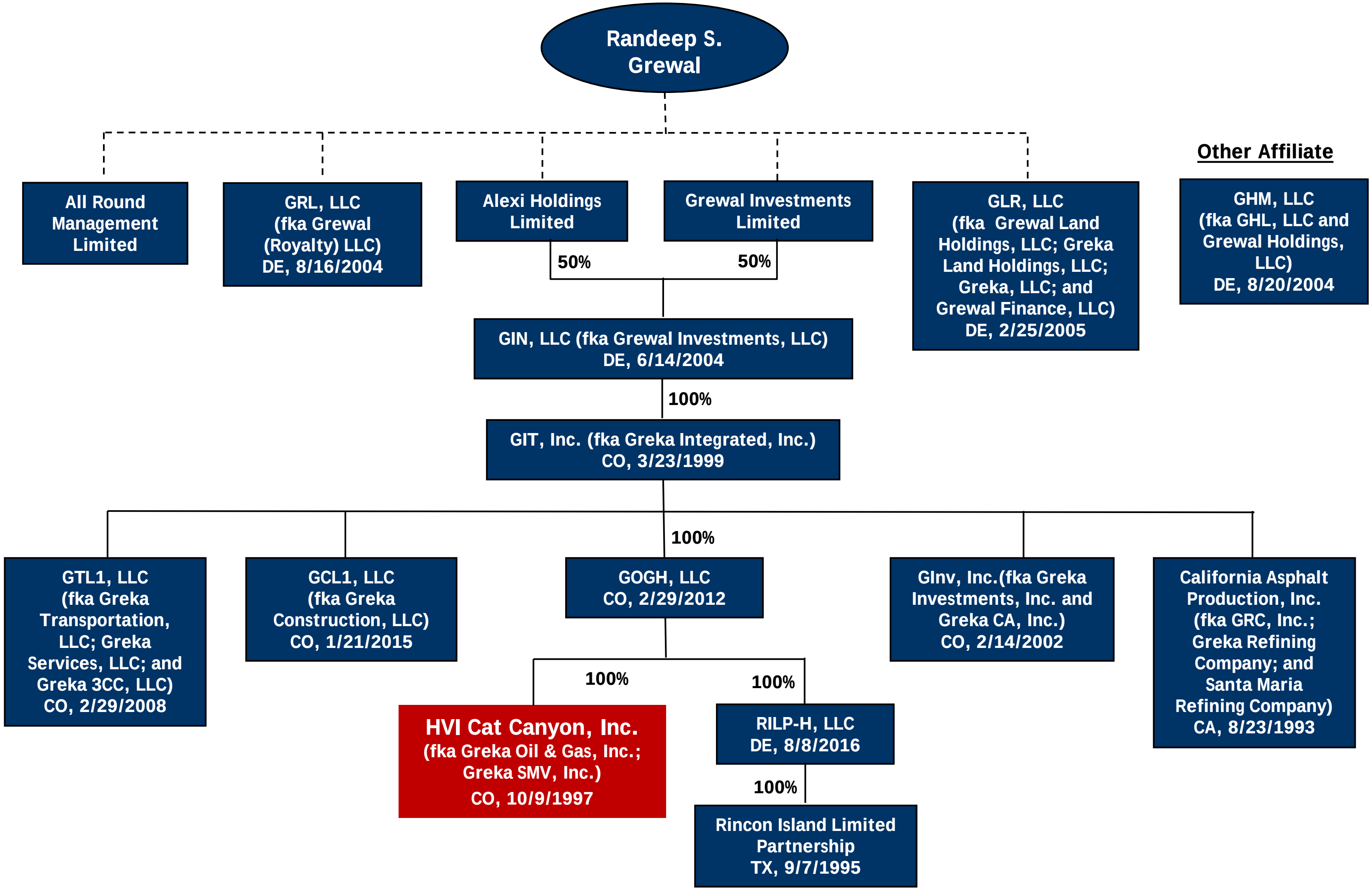
Updated Exhibit 1: HVI Cat Canyon, Inc. Organizational Chart



Sources: TREX US2584 at EPA9_0276083 (Greka Corporate Relationship Chart); US2583 at HVIFIN0000892 (Greka California Organizational Chart); TREX US2524 at HVI084279 (Resolutions of the Board of Directors of HVI- CC, Inc, 8/8/2016); Testimony of Susan Whalen on October 4-5, 2016, pp. 46: 2-21, 47:5-6, 48:9-11, 51:4-8, 52:8-10, 53:25, 54:1-5 &21-25, 286:21-22; TREX US2659 at HVI082803 (Greka Integrated 2015 Tax Returns Form 851); Secretary of State filings; TREX US3239 at HVI085716 & 23 (GIT, Inc., Consolidated Financial Statements, 2015 & 2016, Note 1 & Note 7).

Updated Exhibit 2: HVI Cat Canyon, Inc. and Subsidiary
Consolidated Balance Sheet

Row		2005	2006	2007	2008	2009	2010	2011
1	**Assets**							
2	Current assets:							
3	Cash and cash equivalents	$ 5,833,651	$ 33,908	$ 1,975,448	$ 6,424,105	$ -	$ 220,082	$ 1,719,492
4	Accounts receivable trade	$ 2,887,239	$ 2,456,354	$ 3,845,339	$ 672,639	$ 1,270,989	$ 1,143,772	$ 1,952,044
5	Inventory	$ 540,486	$ 590,061	$ 1,729,753	$ 245,477	$ 676,456	$ 403,274	$ 242,325
6	Receivables from affiliates, net	$ 14,511,408	$ 6,460,057	$ 18,733,500	$ 4,546,868	$ 3,084,432	$ 3,199,891	$ 13,112,609
7	Other current assets	$ 268,115	$ 150,478	$ 1,108,239	$ 2,590,329	$ 472,207	$ 1,294,552	
8	**Total Current Assets**	**$ 24,040,899**	**$ 9,690,858**	**$ 27,392,279**	**$ 14,479,418**	**$ 5,504,084**	**$ 6,261,571**	**$ 17,026,470**
9	Oil & gas properties (full cost method)	$ 68,600,827	$ 75,845,848	$ 85,377,842	$ 92,794,621	$ 97,450,760	$ 104,962,367	$ 116,071,638
10	Plant and equipment	$ 1,467,112	$ 1,955,901	$ 2,064,006	$ 2,036,052	$ 2,068,212	$ 2,317,762	$ 255,397
11	less Depreciation & Depletion	$ (5,434,576)	$ (7,421,227)	$ (8,488,406)	$ (8,831,878)	$ (11,491,354)	$ (14,321,613)	$ (17,736,662)
12	Total PPE less deprec. & depletion	$ 64,633,363	$ 70,381,522	$ 78,953,442	$ 85,998,795	$ 88,027,618	$ 92,958,516	$ 98,590,373
13	Intercompany/ Receivable from affiliate, net	$ 76,141,188	$ 89,420,996	$ 96,808,332	$ 103,246,023	$ 117,802,672	$ 84,162,901	$ 81,926,531
14	Deposits							
15	Other assets, net	$ 9,193,139	$ 8,134,635	$ 6,343,760	$ 6,032,599	$ 5,401,045	$ 5,265,307	$ 5,073,569
16	**Total Assets**	**$ 174,008,589**	**$ 177,628,011**	**$ 209,497,813**	**$ 209,756,835**	**$ 216,735,419**	**$ 188,648,295**	**$ 202,616,943**
17	**Liabilities and Stockholders' Equity**							
18	**Current liabilities:**							
19	Bank overdraft					$ 680,793	$ -	
20	Accounts payable	$ 1,680,853	$ 1,864,867	$ 1,226,041	$ 1,719,785	$ 2,079,790	$ 2,179,952	$ 2,408,346
21	Accrued expenses	$ 1,096,574	$ 2,146,811	$ 2,385,724	$ 2,103,673	$ 3,010,596	$ 4,020,716	$ 3,826,303
22	Deferred revenue			$ 14,949,992	$ 16,017,998	$ 3,784,000	$ 12,404,075	$ 14,309,713
23	Long-term debt- current portion			$ -	$ 35,900,000	$ -	$ 550,000	$ 425,000
24	Royalties payable	$ 3,252,448	$ 4,710,913	$ 3,105,438	$ 4,943,494	$ 4,173,330	$ 4,822,532	$ 6,079,345
25	Notes payable- related parties							
26	VPP obligation payable							
27	**Total Current Liabilities**	**$ 6,029,875**	**$ 8,722,591**	**$ 21,667,195**	**$ 60,684,950**	**$ 13,728,509**	**$ 23,977,275**	**$ 27,048,707**
28	Long-term debt	$ 150,000,000	$ 150,000,000	$ 32,900,000	$ -	$ 35,900,000	$ 1,450,000	$ 975,000
29	Note payable- related party			$ -	$ 21,747,783	$ 26,543,683	$ 29,910,086	$ 33,632,712
30	VPP obligation payable							
31	Deferred revenue	$ -	$ -	$ 133,967,741	$ 119,296,556	$ 128,517,650	$ 114,924,163	$ 110,188,630
32	Suspended royalties payable							
33	Asset retirement obligation	$ 1,508,845	$ 1,635,183	$ 1,848,483	$ 2,130,664	$ 2,444,903	$ 2,756,031	$ 3,509,261
34	Contingency							
35	Other liabilities	$ 1,195,105	$ 1,195,105	$ 1,233,093	$ -			
36	**Total Liabilities**	**$ 158,733,825**	**$ 161,552,879**	**$ 191,616,512**	**$ 203,859,953**	**$ 207,134,745**	**$ 173,017,555**	**$ 175,354,310**
37	**Shareholders' Equity**							
38	Common stock	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Retained Earnings	$ 15,274,764	$ 16,075,132	$ 17,881,301	$ 5,896,881	$ 9,600,674	$ 15,630,740	$ 27,262,633
40	**Total shareholders' equity**	**$ 15,274,764**	**$ 16,075,132**	**$ 17,881,301**	**$ 5,896,881**	**$ 9,600,674**	**$ 15,630,740**	**$ 27,262,633**
41	**Total Liab. & Shareholders' Equity**	**$ 174,008,589**	**$ 177,628,011**	**$ 209,497,813**	**$ 209,756,834**	**$ 216,735,419**	**$ 188,648,295**	**$ 202,616,943**

Sources:

TREX US2610 at HVIFIN0002068 & 69; US2586 at HVI0605349 and 50; US2588 at HVI065332 and 33; US2619 at HVI065315 and 16; US2620 at HVI076581 and 82; US2673 at HVIFIN0000634 and 35; US2590 at HVI084240 and 41; US3233 at HVI085662 and 63, HVI Cat Canyon, Inc. (fka GREKA Oil & Gas, Inc.) and Subsidiary Consolidated Financial Statements, Balance Sheet, Years Ended December 31, 2005-2016.

TREX US3234 at HVI085680; US3235 at HVI085682 and 84, Unaudited HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements, Balance Sheet, Years Ended December 31, 2017, March 31, 2018, and May 31, 2018.

Updated Exhibit 2: HVI Cat Canyon, Inc. and Subsidiary
Consolidated Balance Sheet

Row		2012	2013	2014	2015	2016	2017 (unaudited)	May 2018 (unaudited)
1	**Assets**							
2	Current assets:							
3	Cash and cash equivalents	$ -	$ -			$ -	$ 80,404	$ 56,122
4	Accounts receivable trade	$ 1,472,477	$ 7,565,215	$ 879,446	$ 584,104	$ 634,665	$ 644,330	$ 921,050
5	Inventory	$ 408,776	$ 236,953	$ 87,643	$ 53,092	$ 56,325	$ 50,441	$ 134,028
6	Receivables from affiliates, net	$ 7,598,312						
7	Other current assets		$ 266	$ 102,520	$ -			
8	**Total Current Assets**	**$ 9,479,565**	**$ 7,802,434**	**$ 1,069,609**	**$ 637,196**	**$ 690,990**	**$ 775,175**	**$ 1,111,200**
9	Oil & gas properties (full cost method)	$ 123,923,373	$ 138,118,954	$ 147,568,652	$ 151,541,357	$ 134,530,159	$ 136,523,268	$ 137,141,672
10	Plant and equipment	$ 281,716	$ 281,716	$ 318,444	$ 318,444	$ 291,557	$ 291,557	$ 292,020
11	less Depreciation & Depletion	$ (19,118,074)	$ (24,290,876)	$ (31,799,851)	$ (39,938,141)	$ (43,048,505)	$ (46,511,997)	$ (47,583,565)
12	Total PPE less deprec. & depletion	$ 105,087,015	$ 114,109,794	$ 116,087,245	$ 111,921,660	$ 91,773,211	$ 90,302,828	$ 89,850,127
13	Intercompany/ Receivable from affiliate, net	$ 74,836,183	$ 68,246,959	$ 73,120,678	$ 64,156,445	$ 91,956,571	$ 114,004,203	$ 114,571,892
14	Deposits					$ 1,011,211		
15	Other assets, net	$ 5,835,315	$ 5,671,153	$ 4,988,038	$ 4,900,283		$ 2,011,806	$ 1,966,856
16	**Total Assets**	**$ 195,238,078**	**$ 195,830,340**	**$ 195,265,570**	**$ 181,615,584**	**$ 185,431,983**	**$ 207,094,012**	**$ 207,500,075**
17	**Liabilities and Stockholders' Equity**							
18	**Current liabilities:**							
19	Bank overdraft							
20	Accounts payable	$ 4,247,357	$ 3,464,296	$ 5,593,323	$ 7,810,060	$ 9,192,245	$ 10,094,499	$ 10,456,473
21	Accrued expenses	$ 3,665,466	$ 2,986,904	$ 3,645,711	$ 3,588,227	$ 4,192,060	$ 5,029,779	$ 5,368,756
22	Deferred revenue	$ 14,245,178	$ 12,258,482	$ 10,704,227	$ -			
23	Long-term debt- current portion	$ 397,222	$ 397,222	$ -				
24	Royalties payable	$ 6,814,052	$ 9,355,013	$ 9,794,882	$ 9,970,267	$ 327,809	$ 3,026,140	$ 3,134,271
25	Notes payable- related parties		$ -	$ 42,819,835	$ -			
26	VPP obligation payable		$ 71,586,027	$ 96,675,242	$ -			
27	**Total Current Liabilities**	**$ 29,369,275**	**$ 100,047,944**	**$ 169,233,220**	**$ 21,368,554**	**$ 13,712,114**	**$ 18,150,418**	**$ 18,959,500**
28	Long-term debt	$ 541,667	$ 108,333	$ -	$ -	$ 101,909,773	$ 106,393,195	$ 107,788,969
29	Note payable- related party	$ 38,124,863	$ 36,991,536	$ -	$ 49,218,287	$ 64,267,948	$ 72,993,480	$ 77,437,717
30	VPP obligation payable				$ 115,766,508			
31	Deferred revenue	$ 99,302,061	$ 94,166,343	$ 89,835,204	$ 97,009,716			
32	Suspended royalties payable					$ 10,073,243		
33	Asset retirement obligation	$ 3,869,261	$ 4,490,700	$ 4,535,049	$ 3,653,565	$ 3,541,880		
34	Contingency						$ 8,162,292	$ 8,505,894
35	Other liabilities						$ 3,901,881	$ 4,051,880
36	**Total Liabilities**	**$ 171,207,127**	**$ 235,804,856**	**$ 263,603,473**	**$ 287,016,630**	**$ 193,504,958**	**$ 209,601,266**	**$ 216,743,960**
37	**Shareholders' Equity**							
38	Common stock	$ -	$ -	$ -	$ -	$ -	$ 21,989,557	$ 21,989,557
39	Retained Earnings	$ 24,030,951	$ (39,974,516)	$ (68,337,903)	$ (105,401,046)	$ (8,072,975)	$ (24,496,811)	$ (31,233,442)
40	**Total shareholders' equity**	**$ 24,030,951**	**$ (39,974,516)**	**$ (68,337,903)**	**$ (105,401,046)**	**$ (8,072,975)**	**$ (2,507,254)**	**$ (9,243,885)**
41	**Total Liab. & Shareholders' Equity**	**$ 195,238,078**	**$ 195,830,340**	**$ 195,265,570**	**$ 181,615,584**	**$ 185,431,983**	**$ 207,094,012**	**$ 207,500,075**

Sources:

TREX US2610 at HVIFIN0002068 & 69; US2586 at HVI0605349 and 50; US2588 at HVI065332 and 33; US2619 at HVI065315 and 16; US2620 at HVI076581 and 82; US2673 at HVIFIN0000634 and 35; US2590 at HVI084240 and 41; US3233 at HVI085662 and 63, HVI Cat Canyon, Inc. (fka GREKA Oil & Gas, Inc.) and Subsidiary Consolidated Financial Statements, Balance Sheet, Years Ended December 31, 2005-2016.

TREX US3234 at HVI085680; US3235 at HVI085682 and 84, Unaudited HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements, Balance Sheet, Years Ended December 31, 2017, March 31, 2018, and May 31, 2018.

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Updated Exhibit 3: HVI Cat Canyon, Inc.
and Subsidiary Consolidated Income

Row		2005	2006	2007	2008	2009	2010	2011
1	**Revenues**	**$ 30,694,687**	**$ 37,296,819**	**$ 39,225,078**	**$ 37,730,678**	**$ 31,066,181**	**$ 39,708,896**	**$ 56,937,728**
2	Operating Expenses:							
3	Production Costs	$ 10,451,465	$ 11,170,134	$ 12,244,413	$ 19,158,469	$ 14,903,999	$ 17,660,685	$ 28,985,295
4	Sales, G&A	$ 1,939,887	$ 3,410,107	$ 2,623,546	$ 8,589,334	$ 3,922,701	$ 7,868,096	$ 8,293,372
5	Depr, depl & amort	$ 1,896,538	$ 1,998,099	$ 1,061,494	$ 343,472	$ 2,973,714	$ 3,141,387	$ 3,607,030
6	**Operating Income**	**$ 16,406,797**	**$ 20,718,479**	**$ 23,295,625**	**$ 9,639,403**	**$ 9,265,767**	**$ 11,038,728**	**$ 16,052,031**
7	Other Income (Expenses):							
8	Gain on loan restructure							
9	Interest expense	$ (8,639,586)	$ (19,610,939)	$ (21,156,009)	$ (21,768,466)	$ (5,899,152)	$ (5,205,394)	$ (4,410,821)
10	VPP volume shortfall							
11	Other income	$ (170,120)	$ 123,795	$ 639,106	$ 144,644	$ 337,178	$ 196,732	$ (9,317)
12	**Other expense, net**	**$ (8,809,706)**	**$ (19,487,144)**	**$ (20,516,903)**	**$ (21,623,822)**	**$ (5,561,974)**	**$ (5,008,662)**	**$ (4,420,138)**
13	Income before inc taxes	$ 7,597,091	$ 1,231,335	$ 2,778,722	$ (11,984,419)	$ 3,703,793	$ 6,030,066	$ 11,631,893
14	Provision for income tax	$ 2,858,812	$ 430,967	$ 972,553	$ -	$ -	$ -	$ -
15	**Net (loss) income**	**$ 4,738,279**	**$ 800,368**	**$ 1,806,169**	**$ (11,984,419)**	**$ 3,703,793**	**$ 6,030,066**	**$ 11,631,893**

Sources:

TREX US2610 at HVIFIN0002070; US2586 at HVI0605351; US2588 at HVI065334; US2619 at HVI065317; US2620 at HVI076583; US2673 at HVIFIN0000636; US2590 at HVI084243; US3233 at HVI085664, HVI Cat Canyon, Inc. (fka GREKA Oil & Gas, Inc.) and Subsidiary Consolidated Financial Statements, income Statement, Years Ended December 31, 2005-2016.

TREX US3234 at HVI085675, 77, 79, and 81; US3235 at HVI085683 and 85, Unaudited HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements, Balance Sheet, Years Ended December 31, 2017, March 31, 2018, and May 31, 2018.

Updated Exhibit 3: HVI Cat Canyon, Inc.
and Subsidiary Consolidated Income

Row		2012	2013	2014	2015	2016	2017 (unaudited)	5/31/2018 (unaudited)
1	**Revenues**	**$ 49,334,083**	**$ 62,400,628**	**$ 60,368,454**	**$ 30,728,404**	**$ 18,539,791**	**$ 23,632,943**	**$ 10,900,685**
2	Operating Expenses:							
3	Production Costs	$ 36,443,077	$ 36,569,472	$ 38,389,990	$ 25,241,598	$ 17,339,248	$ 17,845,587	$ 7,778,155
4	Sales, G&A	$ 6,694,978	$ 6,828,518	$ 8,055,069	$ 6,356,620	$ 4,151,574	$ 3,835,597	$ 1,413,662
5	Depr, depl & amort	$ 1,741,412	$ 5,598,668	$ 7,553,324	$ 8,498,290	$ 4,499,801	$ 3,823,492	$ 1,221,569
6	**Operating Income**	**$ 4,454,616**	**$ 13,403,970**	**$ 6,370,071**	**$ (9,368,104)**	**$ (7,450,832)**	**$ (1,871,733)**	**$ 487,299**
7	Other Income (Expenses):							
8	Gain on loan restructure					$ 112,776,224		
9	Interest expense	$ (7,836,117)	$ (7,328,845)	$ (13,895,004)	$ (14,252,076)	$ (11,688,284)	$ (16,240,683)	$ (7,143,018)
10	VPP volume shortfall		$ (27,904,034)	$ (21,030,172)	$ (13,381,921)			
11	Other income	$ 149,819	$ 1,045,970	$ 191,718	$ (61,042)	$ 93,583	$ 1,688,581	$ (42,801)
12	**Other expense, net**	**$ (7,686,298)**	**$ (34,186,909)**	**$ (34,733,458)**	**$ (27,695,039)**	**$ 101,181,523**	**$ (14,552,102)**	**$ (7,185,819)**
13	Income before inc taxes	$ (3,231,682)	$ (20,782,939)	$ (28,363,387)	$ (37,063,143)	$ 93,730,691	$ (16,423,835)	$ (6,698,520)
14	Provision for income tax	$ -	$ -	$ -	$ -	$ -	$ -	
15	**Net (loss) income**	**$ (3,231,682)**	**$ (20,782,939)**	**$ (28,363,387)**	**$ (37,063,143)**	**$ 93,730,691**	**$ (16,423,835)**	**$ (6,698,520)**

Sources:

TREX US2610 at HVIFIN0002070; US2586 at HVI0605351; US2588 at HVI065334; US2619 at HVI065317; US2620 at HVI076583; US2673 at HVIFIN0000636; US2590 at HVI084243; US3233 at HVI085664, HVI Cat Canyon, Inc. (fka GREKA Oil & Gas, Inc.) and Subsidiary Consolidated Financial Statements, income Statement, Years Ended December 31, 2005-2016.

TREX US3234 at HVI085675, 77, 79, and 81; US3235 at HVI085683 and 85, Unaudited HVI Cat Canyon, Inc. and Subsidiary Consolidated Financial Statements, Balance Sheet, Years Ended December 31, 2017, March 31, 2018, and May 31, 2018.

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Updated Exhibit 4: HVI Cat Canyon, Inc. and Subsidiary
Consolidated Statement of Cash Flows

Row		2005	2006	2007	2008
1	**Cash flows from operating activities**				
2	Net income (loss)	$ 4,738,279	$ 800,368	$ 1,806,169	$ (11,984,419)
3	Deprec., depletion and amort.	$ 1,896,538	$ 1,998,099	$ 1,061,494	$ 343,472
4	Interest included in deferred revenue				
5	Interest capitalized into VPP obligation payable				
6	Interest capitalized into principal on related party debt				
7	Accretion of asset retirement obligation				
8	Amortization of deferred revenues				
9	Gain on loan restructure				
10	Non-cash interest expense as a result of PIK election				
11	Non-Cash income as a result of loan restructure				
12	Non cash settlement				
13	Caoitalized interest on related party debt				
14	Interest capitalized into principal on LT debt				
15	Accretion expense			$ 213,300	$ 282,181
16	VPP volume shortfall				
17	**Changes in operating assets and liabilities:**				
18	Accounts receivable	$ (467,497)	$ 430,885	$ (1,388,985)	$ 3,172,700
19	Other current assets	$ (112,912)	$ 117,637	$ (957,761)	$ (1,482,090)
20	Receivables from affiliates	$ (10,498,961)	$ 8,051,351	$ 5,726,557	$ 14,186,632
21	Inventory	$ (340,963)	$ (49,575)	$ (1,139,692)	$ 1,484,276
22	VPP proceeds			$ 30,815,473	$ -
23	Amortization of deferred revenues			$ (12,582,267)	$ (13,603,179)
24	Intercompany				
25	Other assets	$ (3,691,651)	$ 1,058,504	$ 1,790,875	$ 311,161
26	Bank overdrafts				
27	VPP obligation payable				
28	Accounts payable and accrued expenses	$ (1,075,313)	$ 1,234,251	$ (910,491)	$ 211,693
29	Royalties payable				
30	Other liabilities	$ 2,437,922	$ 1,584,803	$ (372,382)	$ 604,963
31	**Net Cash Provided (used) by Operating Activities**	**$ (7,114,558)**	**$ 15,226,323**	**$ 24,062,290**	**$ (6,472,610)**
32	**Cash flows from investing activities**				
33	Investment in oil and gas property and equipment				
34	Advances from (to) affiliate, net	$ (76,141,188)	$ (13,279,808)	$ (10,387,336)	$ 15,310,092
35	Proceeds from sale of oil and gas properties				
36	Purchases of oil and gas property and equipment	$ (5,910,603)	$ (7,746,258)	$ (9,633,414)	$ (7,388,825)
37	**Net cash provided by (used in) investing activities**	**$ (82,051,791)**	**$ (21,026,066)**	**$ (20,020,750)**	**$ 7,921,267**
38	**Cash flows from financing activities**				
39	Repayment of debt			$ (2,100,000)	$ -
40	Intercompany, net				
41	Proceeds from note payable related party				
42	Proceeds from debt			$ -	$ 3,000,000
43	Increase in long-term debt	$ 95,000,000	$ -		
44	**Net Cash provided by financing activities**	**$ 95,000,000**	**$ -**	**$ (2,100,000)**	**$ 3,000,000**
45	**Net increase (decrease) in cash and cash equivalents**	**$ 5,833,651**	**$ (5,799,743)**	**$ 1,941,540**	**$ 4,448,657**
46	**Cash and cash equivalents, beginning of year**	$ -	$ 5,833,651	$ 33,908	$ 1,975,448
47	**Cash and cash equivalents, end of year**	**$ 5,833,651**	**$ 33,908**	**$ 1,975,448**	**$ 6,424,105**
48	Cash paid for interest	$ 8,269,222	$ 17,286,547	$ 18,289,056	$ 23,061,365
49	Change to net oil and gas properties related to asset retirement obligation liabilities				
50	VPP proceeds lent to related party			$ 15,000,000	$ -
51	VPP proceeds used to pay interest expense on long-term debt			$ 684,527	$ -
52	VPP proceeds used to pay long-term debt			$ 115,000,000	$ -
53	Intercompany extinguishment of debt				
54	Accrued interest on intercompany receivable				
55	Reduction of intercompany receivable				
56	Issuance of note payable for settlement of liability				
57	Accrual of deferred finance fees				
58	Additions to property and asset retirement obligation				

Sources:

TREX US2610 at HVIFIN0002072; US2586 at HVI0605353 and 54; US2588 at HVI065336; US2619 at HVI065319; US2620 at HVI076585; US2673 at HVIFIN0000638; US2590 at HVI084245; US3233 at HVI085666, HVI Cat Canyon, Inc. (fka GREKA Oil & Gas, Inc.) and Subsidiary Consolidated Financial Statements, Balance Sheet, Years Ended December 31, 2005-2016.

Updated Exhibit 4: HVI Cat Canyon, Inc. and Subsidiary
Consolidated Statement of Cash Flows

Row		2009	2010	2011	2012
1	**Cash flows from operating activities**				
2	Net income (loss)	$ 3,703,793	$ 6,030,066	$ 11,631,893	$ (3,231,682)
3	Deprec., depletion and amort.	$ 2,973,714	$ 3,141,387	$ 3,607,030	$ 1,741,412
4	Interest included in deferred revenue	$ 4,030,164	$ -	$ 725,806	$ 2,110,335
5	Interest capitalized into VPP obligation payable				
6	Interest capitalized into principal on related party debt				
7	Accretion of asset retirement obligation				
8	Amortization of deferred revenues			$ (3,555,701)	$ (13,061,439)
9	Gain on loan restructure				
10	Non-cash interest expense as a result of PIK election				
11	Non-Cash income as a result of loan restructure				
12	Non cash settlement	$ -	$ 2,000,000		
13	Caoitalized interest on related party debt				
14	Interest capitalized into principal on LT debt	$ -	$ 3,366,403	$ 3,722,626	$ 4,492,151
15	Accretion expense				
16	VPP volume shortfall				
17	**Changes in operating assets and liabilities:**				
18	Accounts receivable	$ (598,350)	$ 127,217	$ (808,272)	$ 479,567
19	Other current assets	$ 2,118,122	$ (822,346)	$ 1,294,552	$ -
20	Receivables from affiliates	$ 1,462,436	$ (115,459)	$ (78,036)	$ -
21	Inventory	$ (430,979)	$ 273,182	$ 160,949	$ (166,451)
22	VPP proceeds				
23	Amortization of deferred revenues	$ (7,043,068)	$ (4,973,412)		
24	Intercompany				
25	Other assets	$ 631,554	$ 135,737	$ 191,738	$ (761,746)
26	Bank overdrafts	$ 680,793	$ (680,793)		
27	VPP obligation payable				
28	Accounts payable and accrued expenses	$ 1,266,928	$ 1,110,287	$ 33,981	$ 1,678,174
29	Royalties payable			$ 1,256,813	$ 734,707
30	Other liabilities	$ (770,164)	$ 649,199		
31	**Net Cash Provided (used) by Operating Activities**	**$ 8,024,943**	**$ 10,241,468**	**$ 18,183,379**	**$ (5,984,972)**
32	**Cash flows from investing activities**				
33	Investment in oil and gas property and equipment				
34	Advances from (to) affiliate, net	$ (9,760,749)	$ (2,260,229)	$ (7,598,312)	$ 12,604,645
35	Proceeds from sale of oil and gas properties			$ -	$ 4,000,000
36	Purchases of oil and gas property and equipment	$ (4,688,299)	$ (7,761,157)	$ (8,485,657)	$ (11,878,054)
37	**Net cash provided by (used in) investing activities**	**$ (14,449,048)**	**$ (10,021,386)**	**$ (16,083,969)**	**$ 4,726,591**
38	**Cash flows from financing activities**				
39	Repayment of debt			$ (600,000)	$ (461,111)
40	Intercompany, net				
41	Proceeds from note payable related party				
42	Proceeds from debt				
43	Increase in long-term debt				
44	**Net Cash provided by financing activities**	**$ -**	**$ -**	**$ (600,000)**	**$ (461,111)**
45	**Net increase (decrease) in cash and cash equivalents**	**$ (6,424,105)**	**$ 220,082**	**$ 1,499,410**	**$ (1,719,492)**
46	**Cash and cash equivalents, beginning of year**	$ 6,424,105	$ -	$ 220,082	$ 1,719,492
47	**Cash and cash equivalents, end of year**	**$ -**	**$ 220,082**	**$ 1,719,492**	**$ -**
48	Cash paid for interest	$ 2,493,462	$ 1,826,991	$ -	$ -
49	Change to net oil and gas properties related to asset retirement obligation liabilities				
50	VPP proceeds lent to related party				
51	VPP proceeds used to pay interest expense on long-term debt				
52	VPP proceeds used to pay long-term debt				
53	Intercompany extinguishment of debt	$ -	$ 35,900,000		
54	Accrued interest on intercompany receivable				
55	Reduction of intercompany receivable				
56	Issuance of note payable for settlement of liability	$ -	$ 2,000,000		
57	Accrual of deferred finance fees				
58	Additions to property and asset retirement obligation			$ 561,248	$ -

Sources:

TREX US2610 at HVIFIN0002072; US2586 at HVI0605353 and 54; US2588 at HVI065336; US2619 at HVI065319; US2620 at HVI076585; US2673 at HVIFIN0000638; US2590 at HVI084245; US3233 at HVI085666, HVI Cat Canyon, Inc. (fka GREKA Oil & Gas, Inc.) and Subsidiary Consolidated Financial Statements, Balance Sheet, Years Ended December 31, 2005-2016.

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Updated Exhibit 4: HVI Cat Canyon, Inc. and Subsidiary
Consolidated Statement of Cash Flows

Row		2013	2014	2015	2016
1	**Cash flows from operating activities**				
2	Net income (loss)	$ (20,782,939)	$ (28,363,387)	$ (37,063,143)	$ 93,730,691
3	Deprec., depletion and amort.	$ 5,598,668	$ 7,553,324	$ 8,498,290	$ 4,139,801
4	Interest included in deferred revenue				
5	Interest capitalized into VPP obligation payable	$ 2,581,867	$ 4,059,043	$ 5,709,345	
6	Interest capitalized into principal on related party debt	$ 4,714,985	$ 5,828,300	$ 6,398,452	
7	Accretion of asset retirement obligation				$ 360,000
8	Amortization of deferred revenues	$ (9,244,816)	$ (5,885,394)	$ (3,529,715)	$ 167,921
9	Gain on loan restructure				$ (112,776,224)
10	Non-cash interest expense as a result of PIK election				$ 3,169,182
11	Non-Cash income as a result of loan restructure				
12	Non cash settlement				
13	Caoitalized interest on related party debt				$ 7,949,661
14	Interest capitalized into principal on LT debt				
15	Accretion expense				
16	VPP volume shortfall	$ 27,904,034	$ 21,030,172	$ 13,381,921	
17	**Changes in operating assets and liabilities:**				
18	Accounts receivable	$ (6,093,004)	$ 6,685,769	$ 295,342	$ (58,508)
19	Other current assets				
20	Receivables from affiliates				
21	Inventory	$ 171,823	$ 149,310	$ 34,551	$ (3,233)
22	VPP proceeds				
23	Amortization of deferred revenues				
24	Intercompany	$ 6,589,224	$ (4,873,720)	$ 8,964,233	$ (3,972,323)
25	Other assets	$ 164,162	$ 580,861	$ 190,275	$ (394,760)
26	Bank overdrafts				
27	VPP obligation payable				
28	Accounts payable and accrued expenses	$ (1,461,623)	$ 2,787,834	$ 2,159,253	$ 2,927,098
29	Royalties payable	$ 2,540,961	$ 439,869	$ 175,385	$ 432,916
30	Other liabilities				
31	**Net Cash Provided (used) by Operating Activities**	**$ 12,683,342**	**$ 9,991,981**	**$ 5,214,189**	**$ (4,327,778)**
32	**Cash flows from investing activities**				
33	Investment in oil and gas property and equipment	$ (14,000,008)	$ (9,486,426)	$ (5,214,189)	$ (2,372,222)
34	Advances from (to) affiliate, net	$ 1,750,000	$ -		
35	Proceeds from sale of oil and gas properties				
36	Purchases of oil and gas property and equipment				
37	**Net cash provided by (used in) investing activities**	**$ (12,250,008)**	**$ (9,486,426)**	**$ (5,214,189)**	**$ (2,372,222)**
38	**Cash flows from financing activities**				
39	Repayment of debt	$ (433,334)	$ (505,555)	$ -	
40	Intercompany, net				
41	Proceeds from note payable related party				$ 6,700,000
42	Proceeds from debt				
43	Increase in long-term debt				
44	**Net Cash provided by financing activities**	**$ (433,334)**	**$ (505,555)**	**$ -**	**$ 6,700,000**
45	**Net increase (decrease) in cash and cash equivalents**	**$ -**	**$ -**		**$ -**
46	**Cash and cash equivalents, beginning of year**	$ -	$ -		$ -
47	**Cash and cash equivalents, end of year**	**$ -**	**$ -**		**$ -**
48	Cash paid for interest	$ -	$ 4,007,661	$ 2,144,279	
49	Change to net oil and gas properties related to asset retirement obligation liabilities		$ -	$ (1,241,484)	
50	VPP proceeds lent to related party				
51	VPP proceeds used to pay interest expense on long-term debt				
52	VPP proceeds used to pay long-term debt				
53	Intercompany extinguishment of debt				
54	Accrued interest on intercompany receivable	$ -	$ 1,388,907	$ -	
55	Reduction of intercompany receivable	$ -	$ (1,900,000)	$ -	
56	Issuance of note payable for settlement of liability				
57	Accrual of deferred finance fees				$ 1,427,330
58	Additions to property and asset retirement obligation	$ 195,573	$ -		$ (471,685)

Sources:

TREX US2610 at HVIFIN0002072; US2586 at HVI0605353 and 54; US2588 at HVI065336; US2619 at HVI065319; US2620 at HVI076585; US2673 at HVIFIN0000638; US2590 at HVI084245; US3233 at HVI085666, HVI Cat Canyon, Inc. (fka GREKA Oil & Gas, Inc.) and Subsidiary Consolidated Financial Statements, Balance Sheet, Years Ended December 31, 2005-2016.

Exhibit E: Crude Oil Price Table

U.S. Energy Information Administration

PETROLEUM & OTHER LIQUIDS

OVERVIEW | DATA | ANALYSIS & PROJECTIONS | GLOSSARY › | FAQS ›

Referring Pages:
- Spot Prices for Crude Oil and Petroleum Products

View History: Daily Weekly Monthly Annual   Download Data (XLS File)

Cushing, OK WTI Spot Price FOB

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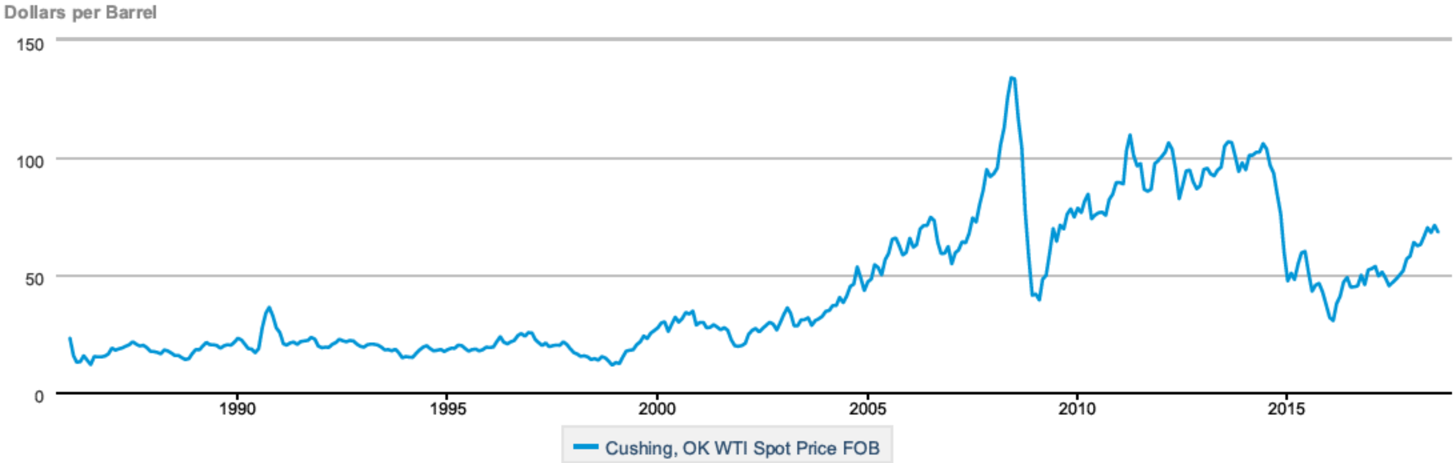

THOMSON REUTERS

Chart Tools
no analysis applied

This series is available through the EIA open data API and can be downloaded to Excel or embedded as an interactive chart or map on your website.

Cushing, OK WTI Spot Price FOB (Dollars per Barrel)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1986	22.93	15.46	12.61	12.84	15.38	13.43	11.59	15.10	14.87	14.90	15.22	16.11
1987	18.65	17.75	18.30	18.68	19.44	20.07	21.34	20.31	19.53	19.86	18.85	17.28
1988	17.13	16.80	16.20	17.86	17.42	16.53	15.50	15.52	14.54	13.77	14.14	16.38
1989	18.02	17.94	19.48	21.07	20.12	20.05	19.78	18.58	19.59	20.10	19.86	21.10
1990	22.86	22.11	20.39	18.43	18.20	16.70	18.45	27.31	33.51	36.04	32.33	27.28
1991	25.23	20.48	19.90	20.83	21.23	20.19	21.40	21.69	21.89	23.23	22.46	19.50
1992	18.79	19.01	18.92	20.23	20.98	22.39	21.78	21.34	21.88	21.69	20.34	19.41
1993	19.03	20.09	20.32	20.25	19.95	19.09	17.89	18.01	17.50	18.15	16.61	14.52
1994	15.03	14.78	14.68	16.42	17.89	19.06	19.66	18.38	17.45	17.72	18.07	17.16
1995	18.04	18.57	18.54	19.90	19.74	18.45	17.33	18.02	18.23	17.43	17.99	19.03
1996	18.86	19.09	21.33	23.50	21.17	20.42	21.30	21.90	23.97	24.88	23.71	25.23
1997	25.13	22.18	20.97	19.70	20.82	19.26	19.66	19.95	19.80	21.33	20.19	18.33
1998	16.72	16.06	15.12	15.35	14.91	13.72	14.17	13.47	15.03	14.46	13.00	11.35
1999	12.52	12.01	14.68	17.31	17.72	17.92	20.10	21.28	23.80	22.69	25.00	26.10
2000	27.26	29.37	29.84	25.72	28.79	31.82	29.70	31.26	33.88	33.11	34.42	28.44
2001	29.59	29.61	27.25	27.49	28.63	27.60	26.43	27.37	26.20	22.17	19.64	19.39
2002	19.72	20.72	24.53	26.18	27.04	25.52	26.97	28.39	29.66	28.84	26.35	29.46
2003	32.95	35.83	33.51	28.17	28.11	30.66	30.76	31.57	28.31	30.34	31.11	32.13
2004	34.31	34.69	36.74	36.75	40.28	38.03	40.78	44.90	45.94	53.28	48.47	43.15
2005	46.84	48.15	54.19	52.98	49.83	56.35	59.00	64.99	65.59	62.26	58.32	59.41
2006	65.49	61.63	62.69	69.44	70.84	70.95	74.41	73.04	63.80	58.89	59.08	61.96
2007	54.51	59.28	60.44	63.98	63.46	67.49	74.12	72.36	79.92	85.80	94.77	91.69

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2008	92.97	95.39	105.45	112.58	125.40	133.88	133.37	116.67	104.11	76.61	57.31	41.12
2009	41.71	39.09	47.94	49.65	59.03	69.64	64.15	71.05	69.41	75.72	77.99	74.47
2010	78.33	76.39	81.20	84.29	73.74	75.34	76.32	76.60	75.24	81.89	84.25	89.15
2011	89.17	88.58	102.86	109.53	100.90	96.26	97.30	86.33	85.52	86.32	97.16	98.56
2012	100.27	102.20	106.16	103.32	94.66	82.30	87.90	94.13	94.51	89.49	86.53	87.86
2013	94.76	95.31	92.94	92.02	94.51	95.77	104.67	106.57	106.29	100.54	93.86	97.63
2014	94.62	100.82	100.80	102.07	102.18	105.79	103.59	96.54	93.21	84.40	75.79	59.29
2015	47.22	50.58	47.82	54.45	59.27	59.82	50.90	42.87	45.48	46.22	42.44	37.19
2016	31.68	30.32	37.55	40.75	46.71	48.76	44.65	44.72	45.18	49.78	45.66	51.97
2017	52.50	53.47	49.33	51.06	48.48	45.18	46.63	48.04	49.82	51.58	56.64	57.88
2018	63.70	62.23	62.73	66.25	69.98	67.87	70.98	68.06				

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 9/12/2018
Next Release Date: 9/19/2018

Referring Pages:

- Spot Prices for Crude Oil and Petroleum Products